Q. Please provide a complete copy of all reports Ms. McShane has reviewed which lists the authorized returns on common equity, and common equity ratios allowed for Canadian electric utilities by Regulatory Agencies and Boards since 2003.

A. The following reports, by regulatory jurisdiction, are attached:

Alberta:

- Attachment A: EUB Generic Cost of Capital Decision, 2004-052.
- Attachment B: Board Initiated Proceeding, 2005 Generic ROE Formula Result, EUB Order U2004-423.
- Attachment C: Board Initiated Proceeding, 2006 Generic ROE Formula Result, EUB Order - U2005-410.
- Attachment D: Board Initiated Proceeding, 2007 Generic ROE Formula Result, EUB Order - U2006-292.

British Columbia;

- Attachment E: TGI TGVI Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism, BCUC Decision March 2006.
- Attachment F: BCUC Letter, Return on Common Equity for a Low-Risk Benchmark Utility for the Year 2007.
- Attachment G: Approval of 2005 Revenue Requirements, 2005-2024 System Development Plan and 2005 Resource Plan, FortisBC, BCUC G-52-05 2005 Decision.
- Attachment H: Pacific Northern Gas Ltd. Project No. 3698411 - Order No. G-134-05, 2006 Revenue Requirements Application.

NEB:

- Attachment I: TransCanada Pipelines Limited, 2004 Mainline Tolls and Tariff Application, NEB Decision RH-2-2004 PHASE II.
- Attachment J: Rate of Return on Common Equity (ROE) for 2004, NEB Letter, 2004.
- Attachment K: Rate of Return on Common Equity (ROE) for 2005, NEB Letter, 2005.
- Attachment L: Rate of Return on Common Equity (ROE) for 2006 NEB Letter, 2006.
- Attachment M: Rate of Return on Common Equity (ROE) for 2007, NEB Letter, 2007.

Newfoundland:

- Attachment N: Newfoundland Power, Inc., PUB Order No. P.U. 19 (2003).

Nova Scotia:

- Attachment O: Application for Approval of Certain Revisions to its Rates, Charges and Regulations, NSUARB-NSPI-P-882, March 2006.
- Attachment P: Application for Approval of Certain Revisions to its Rates, Charges and Regulations, NSUARB-NSPI-P-881, March 2005.

Northwest Territories:

- Attachment Q: Northland Utilities (Yellowknife) Limited, 2005/06 General Rate Application, Board Decision 12/2005.
- Attachment R: Northland Utilities (NWT) Decision 9-2006.
- Attachment S: Northwest Territories Power Corporation, Phase 1 GRA, Decision 13-2007, August 2007.

Ontario:

- Attachment T: Union Gas Ltd. and Enbridge Gas Distribution Inc. A Review of the Board's Guidelines for Establishing Their Respective Return on Equity - Decision and Order RP-2002-0158.
- Attachment U: Natural Resource Gas Ltd. 2007 Rates, OEB Decision with Reasons, EB-2005-0544.
- Attachment V: OEB, Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, December 2006.
- Attachment W: Enbridge Gas Distribution Inc., 2007 Rates, Decision with Reasons – Phase 1, EB-2006-0034.
- Attachment X: Hydro One Networks Inc., For 2007 and 2008 Electricity Transmission Revenue Requirements, Decision with Reasons, EB-2006-0501.

PEI:

- Attachment Y: Maritime Electric Company Limited, for the approval of proposed amendments to its rates, Order UE06-03.

Quebec:

- Attachment Z: Gaz Metro, Decision (French), D-2004-196, September 2004.

EUB Generic Cost of Capital Decision 2004-052

Decision **2004-052**

Generic Cost of Capital

AltaGas Utilities Inc.
AltaLink Management Ltd.
ATCO Electric Ltd. (Distribution)
ATCO Electric Ltd. (Transmission)
ATCO Gas
ATCO Pipelines
ENMAX Power Corporation (Distribution)
EPCOR Distribution Inc.
EPCOR Transmission Inc.
FortisAlberta (formerly Aquila Networks)
NOVA Gas Transmission Ltd.

July 2, 2004

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2004-052: Generic Cost of Capital
AltaGas Utilities Inc.
AltaLink Management Ltd
ATCO Electric Ltd. (Distribution)
ATCO Electric Ltd. (Transmission)
ATCO Gas
ATCO Pipelines
ENMAX Power Corporation (Distribution)
EPCOR Distribution Inc.
EPCOR Transmission Inc.
FortisAlberta (formerly Aquila Networks)
NOVA Gas Transmission Ltd.
Application No. 1271597

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1 INTRODUCTION AND BACKGROUND

On May 6, 2002, the Board received a request from the City of Calgary[1] (Calgary) that the Board institute a proceeding to consider generic cost of capital matters for electric and gas utilities under the Board's jurisdiction. The Board responded to Calgary by letter dated June 6, 2002, indicating that it would be appropriate to await the National Energy Board's (NEB) upcoming decision on rate of return before proceeding to deal with this issue.

On September 30, 2002, the Board distributed a letter (attached as Appendix 3) to interested parties indicating that it had decided to call a generic hearing, pursuant to Section 46 of the *Public Utilities Board Act*[2] (PUBA), to consider cost of capital matters for electric, gas and pipeline utilities under its jurisdiction. Gas transmission (pipeline) and electric transmission companies as well as electric and gas distribution companies under the Board's jurisdiction would be included.

In its letter of September 30, 2002, the Board advised that it intended to hold a pre-hearing meeting to deal with the following issues:

- Determination of the scope of the proceeding and list of issues.
- Determination of procedural matters that might be adopted for such a hearing.

A preliminary list of issues and procedural matters was attached to the September 30, 2002 letter. Interested parties were requested to consider the preliminary list of issues and procedural matters and provide the Board with their written submissions on the appropriateness of each issue or matter, as well as their submissions with respect to additional issues or matters that might appropriately be considered through such a generic proceeding.

1 In its May 28, 2003 letter, the Board indicated that for purposes of the proceeding, utility companies would be considered as applicants and all other parties as interveners.
2 R.S.A. 2000, c. P-45

On October 7, 2002, the Board issued a Notice of Proceeding (the Notice). By letter of November 20, 2002, the Board advised parties that their written submissions as a result of the Board's September 30, 2002 letter had been sufficient to clarify the parties' positions with respect to the preliminary issues list and that a pre-hearing meeting was therefore not necessary.

By letter dated December 16, 2002, the Board clarified the next steps in the process with respect to a Generic Cost of Capital proceeding. The Board, in establishing this process, gave regard to the submissions, concerns and questions initially filed by parties pursuant to the Board's letter of September 30, 2002 and the reply submissions filed pursuant to the Board's letter of November 26, 2002. The Board set out its rational for consideration of a generic approach to cost of capital issues and established an initial process module (the Standardized Approach Module) to consider the preliminary question of the appropriateness of a standardized approach in the following manner:

> The Board continues to seek out opportunities to improve and streamline the regulatory process and to decrease the overall cost of regulation. The Board is of the view that the cost of capital matters for gas, pipeline, and electric utilities under its jurisdiction are one such area worthy of consideration, particularly given its importance within GTA/GRA proceedings.
>
> The Board notes the amount of regulatory time and accompanying expense that is expended, whereby parties are engaged in seemingly similar cost of capital issues in multiple applications. Applicants and interveners often address these issues through similar investigative, comparative and interpretive methodologies and cost of capital evidence.
>
> The Board is also cognizant of the increasingly heavy utility regulatory schedule that has resulted from electric and gas industry restructuring, new and expanding Board responsibilities, and the general growth and prosperity of the Province.
>
> The Board notes that in previous proceedings, such as the 99/00 Electric GTA, the Board has addressed the uniformity in treatment between utilities on cost of capital matters by hearing the consolidated evidence from all applicants in the same proceeding and rendering a single Board decision (as occurred in Decision U99099). The Board has also attempted to streamline proceedings in other ways, such as the development of policy guidelines like the Negotiated Settlement Guidelines.
>
> In a first module as discussed below, the Board, following submissions from parties, will assess and determine whether or not to proceed further, in a generic process on this issue. This first module will explore the ability and appropriateness of possibly applying a standardized approach in Alberta for all major gas, pipeline and electric utilities under its jurisdiction, whether collectively or on an industry-by-industry basis. Such an approach may magnify the benefits to all parties and enhance the sustainability of the cost of capital determination process, and thereby streamline the regulatory process. The Board wishes to also explore whether the simultaneous airing of views is likely to be more cost-effective than a separate airing of views over a series of proceedings, which may not be linked in evidentiary terms.

The Board then concluded:

> The Board has determined that it will proceed with a written process followed by a Board decision to address the preliminary issue of whether a standardized approach to cost of capital, including return on equity, capital structure and cost of debt, has the potential to achieve reasonable efficiencies while continuing to result in fair and reasonable rates for all stakeholders. As part of the decision, the Board will determine the subsequent steps, if any, for this generic proceeding.

The Board also presented the initial questions to be considered in the Standardized Approach Module and the Board set out the schedule for the Standardized Approach Module.

Having reviewed the written submissions of the parties on the preliminary questions in the Standardized Approach Module, the Board concluded this module on April 16, 2003 by issuing a Notice of Hearing in respect of the continuation of the Generic Cost of Capital proceeding. The Board noted:

> Having considered the submissions received from the above parties, the Board is of the view that a standardized approach to rate of return on equity and capital structure has the potential to achieve certain positive benefits including reduced regulatory costs, while continuing to result in a fair return for all utilities and in just and reasonable rates for all customers. The Board has therefore determined that it will proceed with a generic cost of capital hearing to focus on the possibility of establishing a standardized approach to rate of return on equity and capital structure for all utilities under the jurisdiction of the Board.

The letter also dealt with transitional issues, minimum filing requirements, and set out a scope for the Generic Cost of Capital Proceeding. The Board also established a preliminary schedule that would result in a hearing commencing on November 12, 2003.

By letter dated May 28, 2003, the Board remarked:

> The Board notes that no party objected to the Board's preliminary scope of the proceeding. Accordingly, the Board confirms the scope for the Generic Cost of Capital Proceeding as set out in Appendix A.

Appendix A of the May 28, 2003 letter outlined the Scope of the Proceeding as follows:

Return on Equity

1. Return on Equity Methodology
2. Allowed 2004 Return on Equity
3. Annual Adjustment Mechanism
4. Process to Review the Return on Equity

Capital Structure

1. Capital Structure for Each Utility Sector
2. Impact on Capital Structure of Utility Holding Company Structures
3. Adjustments to Capital Structure for Non-Taxable Entities
4. 2004 Capital Structure for Each Utility Company
5. Events and Process Which Might Result in Adjustments to Capital Structure

Also in the May 28, 2003 letter, the Board clarified certain transitional issues, refined the minimum filing requirements and indicated that for purposes of the proceeding, utility companies would be considered as applicants and all other parties as interveners. The Applicants are shown below:

Applicant	**Abbreviation**
AltaGas Utilities Inc.	AltaGas
AltaLink Management Ltd.	AltaLink
FortisAlberta (formerly Aquila Networks)	
The ATCO Group of Companies[3]	ATCO
ENMAX Power Corporation (Distribution)	ENMAX
The EPCOR Group of Companies[4]	EPCOR
NOVA Gas Transmission Ltd.	NGTL

A complete list of Participant organizations and their abbreviations is provided in Appendix 1. AltaLink, Aquila and EPCOR collectively referred to themselves as "the Companies". The Board notes that effective May 31, 2004, Fortis Alberta Holdings Inc. (Fortis) completed its acquisition of Aquila and renamed the company FortisAlberta. Any Board decisions or directions in this Decision respecting Aquila should be read as decisions or directions respecting FortisAlberta.

The Board's May 28, 2003 letter also included a Preliminary Schedule shown below:

Notice of Hearing	April 16, 2003
Submissions	May 12, 2003
Reply Submissions	May 20, 2003
Ruling on Procedural and Transitional Issues	May 28, 2003
Utility Applicants Evidence	July 9, 2003
Information Requests (IRs) to Utilities	July 25, 2003
IR Responses from Utilities	August 15, 2003
Intervener Evidence	September 12, 2003
IRs to Interveners	September 26, 2003
IR Responses from Interveners	October 17, 2003
Utility Rebuttal Evidence	November 5, 2003
Hearing Commencement	November 12, 2003

By letter dated, June 24, 2003, the Board clarified the minimum filing requirements, identified electronic filing requirements, and pre-assigned exhibit numbers.

On August 19, 2003, the Board issued a letter advising parties of hearing logistics and a tentative pre-hearing meeting date to resolve scheduling and procedural matters.

By letter dated October 9, 2003, the Board noted that parties generally did not see a need to convene a pre-hearing meeting and accordingly the Board cancelled the meeting that had tentatively been scheduled for October 16, 2003.

[3] ATCO Electric Ltd., ATCO Gas, and ATCO Pipelines
[4] EPCOR Distribution Inc. and EPCOR Transmission Inc.

The Board conducted a public hearing from November 12-14, 2003, November 17-21, 2003 and November 25-27, 2003 at the Board's offices in Edmonton, and from December 1-5, 2003, December 8-12, 2003, December 15-16, 2003, January 5-9, 2004, and January 12-16, 2004, at the Board's offices in Calgary. A list of parties who appeared at the hearing is included in Appendix 1. The Board sat for a total of 33 hearing days.

The Board received written argument on or before February 23, 2004 and written reply on or before April 5, 2004. Accordingly, for purposes of this Decision, the Board considers that the record closed on April 5, 2004.

The Board notes the full participation of a broad range of stakeholders in the proceeding, the large number of parties involved, and the diversity and sophistication of the views represented. The Board also notes the extensive nature of the record of the proceeding which includes pre-hearing submissions, the minimum filing requirements, a thorough set of responses to information requests, detailed expert evidence, hearing transcripts, undertaking responses, and comprehensive argument and reply argument.

Having considered all of the evidence and reviewed the arguments of the interested parties, the Board sets out its Decision with reasons respecting the Generic Cost of Capital Proceeding (Proceeding).

Abbreviations not otherwise defined within the body of the Decision are defined in Appendix 2.

2 SHOULD THE BOARD ADOPT A STANDARDIZED APPROACH TO RATE OF RETURN AND/OR CAPITAL STRUCTURE?

2.1 NGTL Jurisdictional Objection

NGTL submitted that the Board does not have the jurisdiction to implement a formula approach to establish a fair return for NGTL.

NGTL submitted that the specific jurisdiction of the Board in respect of the determination of the fair return for any gas utility comes only from section 37 of the Alberta *Gas Utilities Act*[5] (GUA). Section 37 reads as follows:

> 37(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility, the Board shall determine a rate base for the property of the owner of the gas utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base.
>
> (2) In determining a rate base under this section, the Board shall give due consideration
>
> a. to the cost of the property when first devoted to public use and to prudent acquisition costs to the owner of the gas utility, less depreciation, amortization or depletion in respect of each, and
>
> b. to necessary working capital.

[5] R.S.A. 2000, c. G-5

> (3) In fixing the fair return that an owner of a gas utility is entitled to earn on the rate base, the Board shall give due consideration to all facts that in its opinion are relevant.

NGTL submitted that based on the wording of subsection 37(1), the Board does not have jurisdiction to fix a fair return for a gas utility "*unless and until it has determined a rate base"* for that gas utility. The rate base will vary from year to year, and the Board must determine the rate base for a particular period before it can determine a fair return for that period. NGTL argued that the Board cannot make a pre-determination of the fair return for a particular period, using a formula, and then apply that return to whatever rate base it subsequently determines is appropriate in respect of that same period. NGTL submitted that application of a formulaic return to a rate base that has yet to be determined would fetter the discretion of future Board panels and is not permitted by the statute.

NGTL also considered the wording of section 45 of the GUA, which provides:

> 45(1) Instead of fixing or approving rates, tolls or charges, or schedules of them, under sections 36(a), 37, 40, 41, 42 and 44, the Board, on its own initiative or on the application of a person having an interest, may by order in writing fix or approve just and reasonable rates, tolls or charges, or schedules of them,
>
> (a) that are intended to result in cost savings or other benefits to be allocated between the owner of the gas utility and its customers, or
>
> (b) that are otherwise in the public interest.
>
> (2) The Board may specify terms and conditions that apply to an order made under this section.

NGTL submitted that section 45 of the GUA was implemented to permit approval of negotiated settlements and does not empower the Board to establish a formulaic approach to fair return. NGTL submitted that by its terms, section 45 relates to "rates, tolls or charges", not to return.

NGTL also submitted that the fact it did not raise the jurisdiction issue in the first module of this proceeding does not prohibit it from raising the issue in argument.

Jurisdiction to Interpret the GUA Provisions

The NGTL position in effect poses the following question: "Does the Board have jurisdiction to fix a fair return for a gas utility through a standardized approach based on a formula?" (the Jurisdictional Question) Before the Board can address this question, it must first determine if it has jurisdiction to interpret the subject provisions of the GUA. The Board finds it does have such jurisdiction on the basis of the reasons stated below.

The Board notes section 36(1)(a) of the PUBA which provides:

> The Board has all the necessary jurisdiction and power
>
> (a) to deal with public utilities and the owners of them as provided in this Act;

The Board further notes section 36(2) of the PUBA, which provides:

> In addition to the jurisdiction and powers mentioned in subsection (1), the Board has all necessary jurisdiction and powers to perform any duties that are assigned to it by statute or pursuant to statutory authority.

In order for the Board to perform the duties assigned to it pursuant to sections 37 and 45 of the GUA, the Board must be able to interpret and apply the wording of the legislation.

Board also notes the provisions of section 38 of the PUBA, which provides:

> The Board may, as to matters within its jurisdiction, hear and determine all questions of law or of fact.

The interpretation of the Board's governing legislation is a question of law or of fact.

The Board further notes the decision of the Alberta Court of Appeal in *ATCO Electric Ltd. v. Alberta* (Energy and Utilities Board) [2003] A.J. No. 1634, (2003) 339 A.R. 152 as a recent acknowledgment of the ability of the Board to construe its own legislation.

Accordingly, the Board finds that the ability to interpret sections 37 and 45 of the GUA is within its jurisdiction.

Is the Matter One of Interpretation?

Next, the Board must determine if the Jurisdictional Question is a matter of interpretation of the relevant provisions.

The Board finds that the Jurisdictional Question is a question of law or of fact, the answer to which is dependant on an interpretation of sections 37 and 45 of the GUA and the relevant legislation taken as a whole. Having found that the interpretation of its own legislation is within the Board's jurisdiction, the provisions of section 38 of the PUBA provide the Board with the authority to settle questions of law or of fact within that jurisdiction.

Accordingly, the Board finds that it has the jurisdiction to address the Jurisdictional Question and that the question is matter of law or of fact, dependant on the interpretation of the relevant statutory provisions.

The Jurisdictional Question

With respect to the Jurisdictional Question itself, the Board finds that the proper interpretation of section 37 of the GUA would allow the Board to determine the capital structure for the relevant test period (2004 or 2005) for each gas utility under its jurisdiction by way of a generic proceeding and to establish a standardized approach based on a formula for determining the return on common equity for gas utilities.

The Board makes this finding for the following reasons:

1. In this Decision, the Board has established a standardized approach to setting a rate of return on common equity (ROE), which is adjusted annually by way of a formula, subject to the limitations set out herein. In addition, this Decision has established the capital structure for each utility for the relevant test period. NGTL objects to the adoption of a formula in setting a fair return that determines a result independently, and prior to, the determination of rate base. Although, the Board does not agree with NGTL's submissions in this regard, it does note and agrees with NGTL's explanation of the elements of fair return when it states on page 2 of its Written Evidence, Exhibit 013-04:

    > The fair return on rate base is fixed by the regulator through determinations of the deemed utility capital structure, the reasonable cost of debt capital and the fair return on equity (ROE) capital.

    In this Decision, the Board has not determined all elements of the fair return for a Utility. The Board has implemented a formula in connection with the determination of ROE with an annual adjustment mechanism. The Board has also set the capital structure for utilities in the Proceeding for the relevant test period. It has not dealt with the cost of debt capital. Further, it has left open the possibility that a utility may request changes in its capital structure with respect to subsequent test periods by way of future general rate applications where circumstances so warrant. An applicant is also free to apply to the Board to review the ROE formula in the manner provided for in this Decision. Even without an application by a particular party, the ROE formula will be subject to review in certain circumstances and in any event will be considered for review after five years.

    This Decision approves a formula and adjustment mechanism for ROE, being one element of a fair return, following a long and complex public process. The result furthers regulatory and cost efficiencies while ensuring fairness to parties and future safeguards to address material changes in circumstance. ROE is not the only element required to determine a fair return. On its own, ROE is not determinative of the fair return component of a utility's revenue requirement. It is only when the ROE is combined with the other elements of the fair return and then applied to the rate base that it is included within the revenue requirement of a utility and subsequently in customer rates. Accordingly, the ROE determined in accordance with the formula approved by this Decision is not included within rates until the remaining relevant elements of a fair return and the rate base applicable for a particular period have been determined. With respect to a particular utility, it is the individual panel(s) of the Board seized with the responsibility of making determinations in respect of the appropriate revenue requirement for a particular test period and with fixing just and reasonable rates which must make the final determination that the revenue requirement, inclusive of all elements of a fair return when combined with the ROE determined in this Proceeding, is appropriate and that the rates are just and reasonable.

    The Board also notes that the embedded cost or appropriateness of existing long term debt is not reconsidered each time that the rate base is determined. Individual long term debt issuances are considered by the Board either when the debt is incurred, on a pre-approval basis, or within a GRA/GTA proceeding. Once approved, long term debt costs normally continue in the revenue requirement for the duration of the debt instrument

2. The Board notes and agrees with the submission of CAPP at page 2 of its Reply Argument that the mechanical approach proposed by NGTL to interpreting the GUA would leave the Board without clear authority to utilize the ROE mechanism in its determination of what is a fair return. In this regard, the Board also notes the decision of the Supreme Court of Canada in *Bell Canada v. Canada* (Canadian Radio-Television and Telecommunications Commission), [1989] 1 S.C.R. 1722 at page 1756 where the Court held:

   > The powers of any administrative tribunal must of course be stated in its enabling statute but they may also exist by necessary implication from the working of the act, its structure and its purpose. Although courts must refrain from unduly broadening the powers of such regulatory authorities through judicial law-making, they must also avoid sterilizing these powers through overly technical interpretations of enabling statutes.

   The Board also notes the decision of the Supreme Court of Canada in *ATCO Ltd. v. Calgary Power* [1982] 2 S.C.R. 557, wherein the Court discusses the nature of the powers of the Board to carry out its responsibilities under the PUBA and the GUA. At page 576, the Court stated:

   > It is evident from the powers accorded to the Board by the legislation in both statutes mentioned above that the legislature has given the Board a mandate of the widest proportions to safeguard the public interest in the nature and quality of the service provided to the community by the public utilities.

   The Board agrees with the following submission of CAPP appearing at page 2 of its Reply Argument:

   > In CAPP's submission, the GUA is properly interpreted as prescribing a form of regulation, namely, rate base/rate of return regulation based on depreciated book cost plus working capital. The GUA does not prescribe how the Board is to determine a fair return and does not prescribe the exact order in which decisions can be made. Nothing precludes the Board from adopting an approach in which rate base is determined independently whatever the level of return and in which return is determined independently of rate base or other cost items such as debt cost. All that is required is that the rates that result would be in accord with the Act, namely, be based on rate base/rate of return among other things.

3. The Board notes that section 45 of the GUA does not require the Board to consider rate base before fixing or approving rates. The Board notes that such rates would include a fair return component either explicitly or implicitly. The Board must consider whether such rates are in the public interest. A consideration of the resultant rates in the context of the public interest is consistent with fixing just and reasonable rates pursuant to section 37 of the GUA and with the Board's approach in this Decision of establishing a just and reasonable standardized approach to establishing rate of return on equity.

With respect to regulatory efficiency, economy of process, cost effectiveness, and procedural fairness to all parties, the Board notes CAPP's submission at page 2 of its Reply Argument that NGTL failed to question the Board's jurisdiction in its submissions on the Standardized Approach Module of the proceeding. The issue that was addressed in that module was whether or not the Board should proceed further with a generic cost of capital process and the ability and appropriateness of possibly adopting a standardized approach. While CAPP acknowledged that jurisdiction couldn't be conferred by consent, it did call into question the merit of the argument.

The Board agrees with CAPP that the appropriate time to challenge the jurisdiction of the Board to establish a standardized approach to elements of a fair return would have been during the submissions leading to the Board's decision on April 16, 2003 to proceed with the generic cost of capital hearing following the Standardized Approach Module. In its letter of December 16, 2002 wherein the Board established the process for the Standardized Approach Module, the Board stated:

> The Board has determined that it will proceed with a written process followed by a Board decision to address the preliminary issue of whether a standardized approach to cost of capital, including return on equity, capital structure and cost of debt, has the potential to achieve reasonable efficiencies while continuing to result in fair and reasonable rates for all stakeholders. As part of the decision, the Board will determine the subsequent steps, if any, for this generic proceeding.

The Board's letter requested parties to respond to specific questions in their submissions. Question 6 requested parties to respond to the following question:

> Would it be correct to consider a standardized approach to setting:
> - Utility equity rate of return;
> - Utility capital structure; and
> - Utility cost of debt,
>
> for all types of gas and electric utilities under the Board's jurisdiction?

NGTL did not raise its jurisdictional concerns in its response to the Board's request for submissions on this first module, nor did NGTL give notice of jurisdictional concerns following the Board's initial module decision to continue with the generic cost of capital proceeding hearing process. In fact, NGTL actively participated in the proceeding, filing evidence, asking information requests of other parties, presenting 3 panels of witnesses for cross-examination and cross examining other parties.

NGTL raised its jurisdictional concerns for the first time in written argument. The Board considers that the appropriate time to have raised the subject jurisdictional concerns was during the initial module process.

2.2 Should the Board Adopt a Standardized Approach?

AltaGas supported a standardized approach to ROE and capital structure, but only if the starting points recommended by Ms. McShane were implemented. Similarly, the Companies had no objection to the adoption of a rate of return adjustment formula providing that the formula was appropriate and contained reasonable starting point values.

ENMAX had reservations regarding the adoption of a generic approach and submitted that a generic approach must be flexible enough to account for differences between utilities and to consistently meet the comparable investment, capital attraction and financial integrity criteria.

ATCO and NGTL opposed a standardized approach to ROE and capital structure. ATCO submitted that a formula approach would not add to consistency, would not add to predictability and would not necessarily reduce regulatory lag.

As discussed in the previous section of this Decision, NGTL submitted that the Board does not have the jurisdiction to implement a formula approach to establish a fair return for NGTL. NGTL also submitted that even if the Board could legally implement a formula approach for NGTL, practical considerations should preclude the Board from doing so; and furthermore, if the Board establishes a formula for NGTL, then the mitigating measures suggested by Dr. Kolbe were essential.

All of the interveners supported a generic approach. Benefits cited for a generic approach generally included improved efficiency of the regulatory process in Alberta, greater consistency between utilities, and greater certainty and predictability of utility returns. Many interveners noted that the NEB and other Canadian regulators have had generic approaches in place for many years, and submitted that there was no reason why a generic approach could not also be used in Alberta.

The Board notes that some Applicants and all interveners supported a generic approach to ROE and capital structure. The Board considers that a generic approach would improve regulatory efficiency. As set out above, the Board does not agree with NGTL that there are legal impediments to the adoption of a generic process for gas utilities. The Board notes that other regulators have successfully implemented generic approaches to ROE and capital structure. Therefore, the Board is not persuaded that there are any practical impediments to the adoption of a generic process for utilities regulated by the Board.

Accordingly, the Board finds that the evidence in the Proceeding indicates that implementation of a generic approach is in the public interest and accordingly, the Board will implement a generic approach to ROE and capital structure. In the following sections, the Board will address the issues associated with the determinations necessary to appropriately implement this approach.

3 LEGISLATIVE AND JUDICIAL FRAMEWORK

In its letter of April 16, 2003, wherein the Board indicated its decision to proceed with a generic hearing, the Board outlined the purpose of the proceeding in the following manner:

> Having considered the submissions received from the above parties, the Board is of the view that a standardized approach to rate of return on equity and capital structure has the potential to achieve certain positive benefits including reduced regulatory costs, while continuing to result in a fair return for all utilities and in just and reasonable rates for all customers. The Board has therefore determined that it will proceed with a generic cost of capital hearing to focus on the possibility of establishing a standardized approach to rate of return on equity and capital structure for all utilities under the jurisdiction of the Board.

This section reviews the legislative and judicial framework that the Board has had regard to in reaching the determinations made herein.

3.1 Legislation

Authority to Hold an Inquiry
By letter dated September 30, 2002, the Board indicated that it had decided to call a generic hearing pursuant to its powers to hold an inquiry under section 46 of the PUBA to consider cost of capital matters for electric, gas and pipeline utilities under its jurisdiction. Section 46 provides the Board with the necessary statutory authority to commence the process that has culminated in this Decision.

The Board also notes that no party has asserted that the Board lacks the jurisdiction to conduct this generic proceeding. The Board notes however, the assertion of NGTL that the Board lacks the jurisdiction to establish a fair return for a gas utility unless and until it has determined a rate base for that gas utility pursuant to subsection 37(1) of the GUA. The Board has dealt with this objection in Section 2 of this Decision.

Authority to Set Fair Return
The Board's jurisdiction to set rates and in particular, a fair return for the utilities under its jurisdiction, is found in the following statutes:

- PUBA, including Part 2, Division 1 and in particular section 90 thereof;
- GUA, including Part 4 thereof and in particular section 37 thereof;
- *Electric Utilities Act*[6] (EUA), including Part 9 thereof and in particular section 122 thereof.

3.2 Relevant Judicial Decisions

Many of the parties quoted passages from decisions of the Supreme Court of Canada and of the U.S. Supreme Court to delineate the relevant judicial guidance for the Board when embarking on a process to establish a fair return for the utilities under its jurisdiction. The Board has provided below extracts from the most frequently cited decisions. These seminal decisions have, in turn, influenced subsequent decisions referred to by the parties.

In *Northwestern Utilities v. the City of Edmonton* [1929] S.C.R. 186; [1929] 2 DLR 4 (*NUL 1929*), the Supreme Court of Canada found at page 192:

> The duty of the Board was to fix fair and reasonable rates: rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise. In fixing this net return, the Board should take into consideration the rate of interest which the company is obliged to pay upon its bonds as a result of having to sell them at a time when the rate of interest payable thereon exceeded that payable on bonds issued at the time of the hearing. To properly fix a fair return the Board must necessarily be informed of the rate of return which money would yield in other fields of investment. Having gone into the matter fully in 1922, and having fixed 10% as a fair return under the conditions then existing, all the Board needed to know, in

[6] S.A. 2003, c. E-5.1

> order to fix a proper return in 1927, was whether or not the conditions of the money market had altered, and, if so, in what direction, and to what extent.[7]

In *Federal Power Commission et al. v. Hope Natural Gas Company*, 320 U.S. 591 (1944) (*Hope*), the U.S. Supreme Court found at page 591:

> The rate-making process under the Act, i.e. the fixing of 'just and reasonable' rates, involves the balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline case that 'regulation does not insure that the business shall produce net revenues'. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view, it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint.[8]

In *Bluefield Waterworks and Improvement Company v. Public Service Commission of the State of West Virginia et al.*, 262 U.S. 679 (1923) (*Bluefield*), the United States Supreme Court found at page 692:

> The company contends that the rate of return is too low and confiscatory. What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgement, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit to enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[9]

The Board notes that no party took issue with the general consensus that in order for a return to be fair, it must meet the tests of "comparable investment", "capital attraction" and "financial integrity" described in the above decisions. The Board concurs that the above decisions are the most relevant judicial authorities with respect to the establishment of a fair return for regulated utilities.

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7 *NUL 1929*, at 192-193

8 *Hope*, at 603

9 *Bluefield*, at 692

4 RETURN ON EQUITY

4.1 Common Return on Equity for all Utilities versus Utility-Specific ROEs

In this section, the Board will address whether there should be a common ROE applicable to all Applicants or whether there should be utility-specific ROEs. The Board will address the potential use of an adjustment mechanism for ROE, which could be applicable to either a common ROE or to utility-specify ROEs, in a later section of this Decision.

The following table summarizes the positions of the parties with respect to the issue of a common ROE applicable to all Applicants versus utility-specific ROEs:

Table 1. Common ROE versus Utility-Specific ROE Requirements

Recommended or Not Opposed to Common ROE	Opposed to Common ROE – Favoured Utility–Specific ROE
AltaGas	Companies
ATCO	NGTL
Calgary	
CAPP	
Cargill	
CG	
ENMAX	
IPCAA	
IPPSA	

Parties who supported a common ROE indicated that differences in business risk should be reflected through adjustments to capital structure. Certain of these parties also indicated that in the event that adjusting capital structure was not adequate to reflect the business risk for a particular Applicant, the common ROE could be adjusted for that particular Applicant. These parties generally took the position that the onus should be on each individual Applicant to establish the need for an exception to the common ROE. Interveners took the position that none of the Applicants had established such a need. ATCO, while supporting a common ROE, submitted that an exception was required for ATCO Pipelines.

The Board does not consider that persuasive arguments were raised against the use of a common ROE. The Board disagrees with NGTL's view that a common ROE fails to recognize the impact of leverage on the cost of equity and with the Companies' view that companies in the same industry may have different investment risks that require different ROEs. In the Board's view, a common ROE approach can accommodate these differences, by adjusting for any material differences in investment risk that would otherwise occur, through an adjustment to the capital structure, or, in exceptional circumstances, through a utility-specific adjustment to the common ROE.

The Board will therefore establish a common, or generic, ROE to be applied to all Applicants. The Board will address the need for any utility-specific adjustments to the common ROE in the capital structure section of this Decision.

In this regard, the Board considers that unique utility-specific adjustments to the common ROE should only be made in exceptional circumstances where adjusting capital structure alone is not sufficient to reflect the investment risk for a particular Applicant.

4.2 ROE Methodology and 2004 ROE

4.2.1 Introduction

The following table summarizes the 2004 ROE recommendations of the expert witnesses:

Table 2. 2004 ROE Recommendations by Expert Witnesses

Witness (Sponsoring Party)	Applies to	ERP Tests ROE Results (%)	DCF Test ROE Results (%)	CE Test ROE Results (%)	2004 Recommended ROE (%)
Ms. McShane[10] (AltaGas/ATCO)	All except ATCO Pipelines	10.5-10.75	11.0-11.25	No less than 13	11.0-11.5
Dr. Evans[11] (Companies)	Companies	9.8-10.4		12 (for ETI)	10.5-11.25
Dr. Neri[12] (ENMAX)	ENMAX	10.05-11.65	10.5-10.95		11.5
Drs. Kolbe & Vilbert[13] (NGTL)	NGTL	11	10.3-14.1,[14] used as check		11 at 40% common equity
Dr. Booth[15] (Calgary/CAPP)	All	8.12	Confirmed ERP of 8.12 was fair	9-10, used as check	8.12
Drs. Kryzanowski & Roberts[16] (CG)	All	8.05			8.05

The Board notes that no party relied directly on an ATWACC approach to setting a fair return for utilities. For the ERP results in the above table, all experts relied at least in part on the CAPM form of the ERP test. Most experts also relied in part on various other tests, including other forms of the ERP test, the DCF test, the CE test, and other measures of comparable investment. The Board will consider each of these approaches in the following sections.

4.2.2 After Tax Weighted Average Cost of Capital

NGTL's evidence (Exhibit 013-03) states:

> In the first phase of this proceeding, NGTL recommended that the Board cast the issues net broadly enough to include methodologies other than the traditional. While the EUB Notice of Hearing does not explicitly exclude the ATWACC approach, it does so implicitly by establishing the scope of the proceeding in capital structure/return on equity terms. NGTL has therefore focused its evidence on the traditional methodology, subject to the fundamental precepts that the cost of equity depends on the amount of financial risk of the company, and that financial risk changes with capital structure.[17]

10 Exhibit 005-10-2, Evidence of Kathleen McShane, page 5
11 Exhibit 003-03, Evidence of Robert E. Evans, pages 24 and 25 and Exhibit 012-01, Evidence of Robert E. Evans Supplement C page C-20
12 ENMAX, Argument, page 16
13 NGTL Argument, page 20
14 Exhibit 013-06, Evidence of Michael J. Vilbert, page 52
15 Calgary/CAPP Argument, page 17 and Exhibit 016-11(a), pages 14 and 36
16 CG Argument, page 47
17 Exhibit 013-03, NGTL Evidence, page 5, line 15

In its Argument, NGTL stated:

> In the first phase of this proceeding, NGTL recommended that the Board cast the issues net broadly enough to include methodologies other than the traditional. The EUB Notice of Hearing implicitly excluded the ATWACC approach by establishing the scope of the proceeding in capital structure/return on equity terms.[18] (Footnotes excluded)

Notwithstanding NGTL's statements that the Board had not explicitly excluded the ATWACC approach, under cross-examination NGTL confirmed that it had not requested the Board to consider the ATWACC approach to cost of capital matters. The following dialogue occurred during examination by Board Counsel of NGTL's witness, Mr. Brett:

> Q………..Are you in the context of your evidence, suggesting that the Board should consider ATWACC and ATWACC methodology in terms of coming up with a fair return for NGTL?
>
> A. MR. BRETT:…..We have not asked the Board to set tolls using an ATWACC methodology which, for example, is what we did in the fair return. What we have indicated is that leverage matters and that capital structure impacts the return that is required; and to our mind, in order to determine that interrelationship, you have to be cognizant of the overall return on capital.
>
> Q……….. So, again, just to be clear, you're not asking the Board to consider ATWACC in terms of how it would set a fair return; moreover, it is being suggested by the company that it is one of the tools it uses as, perhaps, a check in terms of what a fair return would be; would that be a fair statement?
>
> A. MR. BRETT: …..I think what I said, and what I intended to say, is we have not asked the Board to use a return on capital or ATWACC for setting a revenue requirement. We have applied for the traditional ROE on equity thickness.[19]

Given the submissions at the beginning of the proceeding, the Board's written views on the scope for the proceeding and the examination during the Hearing, the Board does not agree with NGTL's stated interpretation of the Board's Notice of Hearing dated April 16, 2003. The Board considers it clear that the Notice of Hearing did not limit, either explicitly or implicitly, any submissions or evidence that a party might wish to present in respect of the approach or the methodology that a party would urge upon the Board to consider in making a determination of an appropriate fair return.

In the Notice of Hearing, the Board stated:

> Having considered the submissions received from the above parties, the Board is of the view that a standardized approach to rate of return on equity and capital structure has the potential to achieve certain positive benefits including reduced regulatory costs, while continuing to result in a fair return for all utilities and in just and reasonable rates for all customers. The Board has therefore determined that it will proceed with a generic cost of capital hearing to focus on the possibility of establishing a standardized approach to rate

[18] NGTL Argument, page 18
[19] Transcript, Volume 20, pages 2777- 2778

> of return on equity and capital structure for all utilities under the jurisdiction of the Board.[20]

It is clear that the Notice refers only to the possibility of establishing a standardized approach to rate of return on equity and capital structure for utilities. Further, in the Board's letter of May 28, 2003, the Board clarified that it had not already made a final determination to adopt a standardized approach to rate of return and capital structure.

> The Board confirms that it expects to adopt a standardized approach to rate of return and capital structure. The Board decided to continue with a generic cost of capital hearing based on a record that supports the overall merits of a standardized approach to rate of return and capital structure. **The Board wishes to emphasize, however, that the approach ultimately adopted by the Board may differ between industries or on some other appropriate basis.**[21] (Emphasis added)

The language in the Board's Notice reinforced the decision of the Board to proceed to a hearing to consider a standardized approach to rate of return and capital structure. However, the last sentence of the paragraph clarified to parties that a standardized approach to rate of return and capital structure may not be found to be appropriate and that the Board remained open to other cost of capital approaches.

The Board also notes the statement of NGTL in their evidence:

> Properly applied, ATWACC and the traditional methodology should yield similar results.[22]

This statement by NGTL clearly indicates its position that the results obtained under one methodology for determining a fair return should be similar to the results obtained through the other methodology, when each methodology is properly applied. The Board also notes that the NGTL evidence and argument provided submissions on an appropriate return on equity and capital structure for NGTL as well as the ATWACC equivalent.[23]

4.2.3 CAPM Test

As noted above, all experts relied at least in part on the CAPM form of the ERP test. The Board will address other forms of the ERP test relied on by the experts in this Proceeding in the next section of this Decision.

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[20] EUB Notice of Hearing, April 16, 2003
[21] Board's letter of May 28, 2003
[22] Exhibit 013-03, NGTL Evidence, page 5
[23] For example Exhibit 013-03, NGTL Evidence, pages 4 and 6 and NGTL Argument pages 19, 89, 92 and 117

The following table summarizes the CAPM recommendations of the expert witnesses:

Table 3. CAPM Recommendations[24]

Witness (Sponsoring Party)	Risk-free Rate (%)	MRP (%)	Beta	Flotation Allowance (%)	ROE (%)
Ms. McShane (AltaGas/ATCO)	5.75	6.0	0.60-0.65[25]	0.50	10.0
Dr. Evans (Companies)	5.60	5.75	0.60	0.75	9.8
Dr. Neri (ENMAX)	6.15	6.5	0.60	0.50[26]	10.5[27]
Drs. Kolbe & Vilbert[28] (NGTL)	5.65	5.5	0.61	0.50[29]	9.5[30]
Dr. Booth (Calgary/CAPP)	5.5	4.5	0.45-0.55[31]	0.50	8.25
Drs. Kryzanowski & Roberts (CG)	5.6	4.7	0.50	0.10	8.05

Risk-Free Rate

A forecast of the long-Canada bond yield is traditionally used as the risk-free rate, for CAPM purposes. The Board notes that none of the experts suggested departing from this practice.

The Board notes from the above table that the range of risk-free estimates was from 5.5-6.15%. Dr. Booth's (sponsored by Calgary/CAPP) estimate of 5.5% was at the low end of the range. However, CAPP noted in argument that the November 2003 Consensus Forecast used by the NEB for its 2004 ROE determination resulted in a forecast of the long-Canada bond yield used by the NEB for 2004 of 5.68%, which would increase CAPP's 2004 ROE recommendations.

The Board notes that Dr. Neri's (sponsored by ENMAX) estimate of 6.15% is significantly higher than any other estimate. Excluding both Dr. Booth's and Dr. Neri's estimates would result in a range of risk-free estimates of 5.60-5.75%.

The Board considers this range of 5.60-5.75% to be a reasonable range for the 2004 risk-free rate, with a midpoint of 5.68%.

The Board notes that this midpoint of 5.68% is the same as the risk-free rate used by the NEB for 2004, which was based on the November 2003 Consensus Forecast. The Board considers the use of a risk-free rate based on the November 2003 Consensus Forecast is consistent with the formula to adjust the generic ROE that the Board establishes in a later section of this Decision. Use of the November 2003 Consensus Forecast is also consistent with the objective of establishing utility revenue requirements based on forecasts made in advance of the test year.

[24] Cargill Argument, page 15, except as otherwise indicated
[25] Exhibit 005-10-2, Evidence of Kathleen McShane, page 30
[26] The Board has added the 0.50% flotation cost indicated in the CAPP/Calgary Argument at page 7
[27] Ibid.
[28] Exhibit 013-06, Table No. MJV-10, panel B, "Average C" ("Averages A & B" are virtually identical to C) and Exhibit 013-06, page 39
[29] Flotation costs assumed to be 50 basis points; NGTL considered flotation costs as a valid cost, but did not make a specific recommendation. NGTL Argument, page 55
[30] Ibid.
[31] Exhibit 016-11(a), Evidence of L.D. Booth, page 23

Therefore, the Board finds that an appropriate risk-free rate for 2004 is 5.68%.

MRP (Market Risk Premium)
The Board notes that some parties, including IPCAA, argued that the arithmetic average MRP overstates the returns that investors have received or can expect to receive in the future. In the Board's view, when a forecast is based on the historic average, the arithmetic average MRP represents the best estimate of the short-term return and the geometric average represents the best estimate of the long-term return. The Board has not been persuaded that it should change its practice of using the arithmetic average. Consequently, the Board will maintain its practice of using the arithmetic average rather than the geometric average.

The following table summarizes the evidence on the average arithmetic MRPs in Canada and the U.S. for various time periods:

Table 4. Historical Arithmetic Canadian and U.S. MRPs

	Canada	U.S.
1802-1998[32]		4.7
1900-2002[33]	5.5	6.4
1924-2002[34]	5.0	
1926-2001[35]		7.0
1936-2002[36]	4.7	
1947-2002[37]	5.0	6.7
1957-2002[38]	2.3	4.2

In this Proceeding, a number of concerns were raised regarding the use of historic data as a reasonable estimate for the future MRP:

1. Dr. Booth indicated that Canadian data prior to 1956 should not be used. However, Dr. Booth indicated that the Canadian equity risk premium since 1956 has been only about 2.3%. Dr. Booth then adjusted this figure upward to 4.5%, to take into account the influence of earlier data, the unexpected performance of the bond market, and the U.S. data.[39] This indicates that Dr. Booth was unable to rely on the historic data without a material adjustment;
2. ATCO noted a number of problems in using Canadian historical data including structural changes in the economy, the recent impact of a few large firms on the market proxy and the need to consider U.S. data;[40] and
3. CG noted that the current equity risk premium could be expected to be about 1% lower than the historical equity risk premium due to current lower trading costs.[41]

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32 Exhibit 016-11(a), Evidence of L.D. Booth, page 33
33 Exhibit 017-05(a), Evidence of Kryzanowski and Roberts, Schedules, Schedule 4.3 and 4.5
34 Exhibit 016-11(a), Evidence of L.D. Booth, Schedule E1 (Canadian Institute of Actuaries Data)
35 Exhibit 012-01, EPCOR Transmission, Direct Evidence and Supplements of Robert E. Evans, Dec. 2002, Supplement C, page C-10
36 Exhibit 009-02(b) Schedule 5 (Canadian Institute of Actuaries data)
37 Exhibit 005-10-2, Table 4, page 27
38 Exhibit 016-11(a), Evidence of L.D. Booth, Appendix E, Schedule E1 and Appendix F, Schedule F2
39 Exhibit 016-11(a), Evidence of L.D. Booth, page 24
40 ATCO Argument, pages 25 and 26
41 CG Argument, page 31

In the Board's view, a reasonable approach is to consider the longer-term average historic Canadian equity risk premium and then adjust this upward or downward based on the Board's judgment and the Board's assessment of the evidence regarding the prospective outlook for the equity risk premium.

In the Board's view, in general, the present Canadian market already reflects the impact of U.S. data based on the current degree of North American market integration. Participants make market trade-offs in their decisions on how to participate in the various markets around the world. The present high degree of integration would not have been fully reflected historically, accordingly, the Board considers that the U.S. historical MRP should be considered as one of many factors in applying judgment to adjust the Canadian historic MRP. The Board notes Dr. Booth's evidence that U.S. MRPs need to be tax-adjusted and that therefore U.S. market returns are biased high for Canada, but still provide a ceiling for Canadian estimates.

The Board notes from Table 3, that the range of the experts' recommended MRP estimates was from 4.5-6.5%, with a midpoint of 5.5%. The Board also notes from Table 4 above that the historic arithmetic risk premium in Canada has been 4.7-5.5% for those periods ending in 2002 that provide 50 or more years of history. In the Board's view, the historic evidence, along with some recognition of the higher U.S. figures, supports the midpoint of the experts' estimates at 5.5%.

Considering all of the above, the Board finds that an MRP of 5.5% is appropriate.

The Board also notes that this midpoint of 5.5% is consistent with the MRP used by the Board in its most recent rate of return determinations.[42]

Beta

The Board notes that there was general agreement that use of actual data from very recent years, to calculate beta, would under-estimate the prospective beta due to the technology-related market bubble and subsequent collapse, and that there was also general agreement that beta is a relative risk factor that requires judgment.

The Board notes from Table 3 that the range of beta estimates recommended by the expert witnesses was from 0.45-0.65. Dr. Booth's estimate of beta of 0.45-0.55 was the lowest estimate in the range. The next lowest estimate was 0.50, proposed by Dr. Kryzanowski (sponsored by CG). The Board also notes from the argument of Calgary/CAPP that the beta of 0.55 recently used by the Board[43] was at the top of Dr. Booth's range, but "is well within normal estimation error".[44] The Board also notes that the high estimate of 0.65 was partially based on adjusted U.S. data and partially based on a relative risk calculation that utilized standard deviations and not the more usual regression analysis calculation.[45]

Based on the above, the Board finds that a reasonable estimate of beta, or the relative risk factor of utilities versus the overall equity market, is 0.55.

[42] Includes Decisions 2003-63, 2003-71, 2003-72 and 2003-100
[43] Decisions 2003-63, 2003-71, 2003-72 and 2003-100
[44] Calgary/CAPP Argument, Section 4.2.3.2, page 15
[45] Exhibit 008-01, ATCO Pipelines 2003-2004 Application, Evidence of Kathleen McShane, pages 44-47 of 63

The Board also notes that this estimate of beta of 0.55 is consistent with the value that the Board has assigned to beta in its most recent rate of return determinations.[46]

Flotation Cost Allowance

The Board notes that all parties, except the Companies and CG, recommended or were not opposed to a 0.50% allowance for flotation costs and financing flexibility.

The Board notes that CG and CAPP suggested that an alternative to an ongoing flotation allowance was to expense the costs of flotation. CG proposed that this expense could be amortized over 50 years. In the Board's view, there was limited support for changing its past approach to flotation costs.

The Board notes that the Companies argued that the flotation allowance should be increased to 0.75%, based on the increased capital markets volatility. However, the Board considers that there is merit in CG's argument that the apparent higher volatility in the markets was due to a rapid increase in listings by smaller and more risky firms and was not due to the utility sector.[47] The Board is therefore not convinced that a change is required to the 0.50% flotation cost allowance used in recent decisions.

Based on the above, the Board finds that continuation of a 0.50% allowance for flotation costs and financing flexibility is appropriate.

CAPM Conclusions

Based on the above-determined risk-free rate of 5.68%, MRP of 5.50%, beta of 0.55, and allowance for flotation costs of 0.50%, the Board concludes that a reasonable CAPM estimate for 2004 is 9.20%.

The Board will now consider the other ROE methodologies suggested by the parties to determine if the results, obtained from the application of such methodologies, warrant an adjustment to the Board's CAPM estimate of ROE.

4.2.4 Other Forms of the ERP Test

Dr. Booth gave equal weight to CAPM and to a multi-factor ERP model that indicated that a utility's equity risk premium over the long-Canada rate was a function of both the MRP and of the term spread of long-Canada rates over shorter-term rates. The midpoint of the results of Dr. Booth's multi-factor ERP model was approximately 7.5%,[48] which indicated an ROE of approximately 8.0% after including an allowance for flotation costs of 0.50%.

Dr. Booth's multi-factor ERP model would directionally support a reduction from the midpoint of the Board's CAPM range. However, the Board will only place limited weight on the results of Dr. Booth's multi-factor model for the following reasons:

1. The model has a low R-squared statistic, indicating low reliability of the model;
2. Today's interest rates are at the bottom edge of the range experienced over the study period; and

[46] Decisions 2003-63, 2003-71, 2003-72 and 2003-100

[47] CG Reply Argument, page 29

[48] Exhibit 016-11(a), Evidence of L. D. Booth, pages 25-29

3. The adjustments that Dr. Booth indicated were required in developing the model.[49]

Dr. Vilbert (sponsored by NGTL) used both a CAPM model and an ECAPM model. His ECAPM model included an adjustment factor to compensate for an alleged tendency of CAPM models to under-estimate required returns for lower risk companies. Dr. Vilbert's ECAPM model resulted in a recommendation for an 11% ROE on a 40% common equity ratio. Dr. Vilbert's ECAPM results would directionally support an increase from the midpoint of the Board's CAPM range.

The Board notes Calgary/CAPP's argument that applying CAPM using long-term interest rates (long-Canada bond yields) in determining the risk-free rate, as was done by all experts in this Proceeding, already corrects for the alleged under-estimation that ECAPM was designed to address.[50] Calgary/CAPP argued that the under estimation would only be present if the CAPM were applied using short-term interest rates, which none of the experts did in this Proceeding.

The Board finds the Calgary/CAPP position persuasive and considers that the use of long-term Canada bond yields largely adjusts for the tendency of CAPM, when based on short-term interest rates, to under estimate the required returns for lower risk companies. Therefore, the Board will only place limited weight on the results of the ECAPM model.

Ms. McShane (sponsored by AltaGas/ATCO) used a DCF-based ERP test that resulted in a utility risk premium of 4.9%.[51] The Board notes that this implies a total utility ROE of 11.15%, after adding her recommended risk-free rate and the flotation cost. Ms. McShane also provided a realized historic utility ERP, based on Canadian and U.S. utility returns, which indicated a utility risk premium of 4.75%.[52] The Board notes that this implies a utility ROE of 11.0%.

Dr. Neri applied two ERP tests in addition to the CAPM, based on U.S. electric utilities and on U.S. gas distribution utilities, which produced utility equity risk premiums of 5.14 and 5.53%,[53] respectively. The Board notes that this implies a total utility ROE of 11.79% and 12.18%, respectively, after adding Dr. Neri's risk-free rate recommendation of 6.15% and a flotation allowance of 0.50%.

The Board notes that these utility return results of Ms. McShane's and Dr. Neri's other ERP tests are higher than many estimates of the market required return.

Ms. McShane's and Dr. Neri's other ERP tests would directionally support an increase from the midpoint of the Board's CAPM range. However, the Board shares CG's[54] and CAPP's[55] concern that it is not reasonable for the prospective required return on low risk firms to be close to or above the prospective overall market return.

49 Exhibit 016-11(a), Evidence of L. D. Booth, page 26
50 Calgary/CAPP Argument, page 12
51 Exhibit 005-10-2, Kathleen McShane, page 33
52 Ibid.
53 Exhibit 009-02(b), Schedules 6&7
54 CG Argument, page 49
55 CAPP Argument, page 17

On balance, the Board concludes that the results of the ERP tests other than CAPM would generally support a 2004 ROE above the Board's CAPM estimate, but that for the reasons set out above only limited weight should be placed on the results of the ERP tests other than CAPM.

4.2.5 Discounted Cash Flow Test

The Board notes from Table 2 that the Applicants' standard-method DCF estimates for ROE ranged from 10.3-14.1%. The Board notes ATCO's argument that any upward bias in analyst growth estimates may be less prevalent for stable industries including utilities. Nevertheless, the Board considers that there is merit in the intervener arguments[56] that the analysts' earnings forecasts used in the development of the DCF estimates have been biased high, resulting in DCF estimates that overstate the required return. The record of the Proceeding reveals no evidence on an appropriate discount to apply to the DCF test results to appropriately adjust for an overstatement in the required returns. Accordingly, the Board finds reliance on the Applicant's DCF estimates problematic.

The Board notes that Dr. Booth's DCF approach[57] was not based on an assessment of analysts' earnings forecasts, but was based on an assessment of the growth of the overall economy. Dr. Booth considered that the market as a whole would grow at the same rate as the nominal GDP growth rate of about 6%, which would indicate a total investor market return of 8.5% after including average dividends of 2.5% (which included an estimated 0.5% to account for share repurchases as surrogate dividends). Dr. Booth indicated that this was a geometric market return estimate and therefore under estimated the average short-run growth rate, since the arithmetic rate exceeds the geometric rate. Dr. Booth further indicated that his DCF analysis confirmed that an 8.12% allowed ROE for a regulated utility was fair and reasonable. However, the Board notes that Dr. Booth did not quantify the impact of converting from a geometric rate to an arithmetic rate, did not quantify, in this case, the impact of utilities having less risk than the market average, and did not add an allowance for flotation costs.

As a result of the above noted concerns, the Board concludes that no weight should be placed on the results of the DCF tests presented in this Proceeding.

4.2.6 Comparable Earnings Test

The Board notes that several Applicants indicated that the comparable investment test, envisioned in the court decisions referred to in Section 3 of this Decision, obligated the Board to place weight on the CE test.[58] However, in the Board's view, the CE test is not equivalent to the comparable investment test. The CE test measures **actual** earnings on **actual book value** of comparable companies, which, in the Board's view, does not measure the return "*it **would** receive if it **were** investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise*"[59] (emphasis added) (unless the securities were currently trading at book value). The Board notes that Cargill[60] expressed a similar view.

56 For example, Cargill Argument, page 23, and CG Argument, page 13
57 Exhibit 016-11(a), Evidence of L.D. Booth, page 36
58 ATCO Argument page 8, Companies Argument page 24
59 NUL, 1929, at 192-193
60 Cargill Argument, pages 6 and 7

The Board considers that the application of a market required return (i.e. required earnings on market value) to a book value rate base is appropriate in the context of regulated utilities.

The Board notes Ms. McShane's CE test result of "no less than 13%". The Board notes that this result is in excess of Ms. McShane's 11.75% estimate of the market return, excluding flotation allowance, incorporated in her CAPM result in Table 3. The Board also notes Dr. Booth's evidence that at no time in the last fourteen years has the average ROE of Corporate Canada exceeded 12.0%, and only twice in the last thirteen years has the average ROE been in double digits.[61]

In the Board's view, based on Dr. Booth's evidence regarding the achieved ROEs of Corporate Canada, and her own CAPM estimate, Ms. McShane's CE test result of "no less than 13%" exceeds a reasonable forecast of the prospective market required return. In the Board's view, CE test results for low risk companies, that exceed the forecast required return on the overall market, raise serious conceptual or methodological concerns regarding the relevance of the CE test. The Board does not consider it reasonable for the prospective required return on low risk firms to exceed the prospective overall market required return. The Board notes Ms. McShane's evidence that lower risk firms have outperformed the market over certain historical periods. However, in the Board's view, to forecast this result would not be credible.

The Board also notes that, in this Proceeding, various implementation problems with the CE test were discussed. These included sample selection problems, accounting differences, market power concerns, and problems matching the current business cycle stage. The Board recognizes that all traditional ROE tests suffer from methodological difficulties.

The Board concludes that it should place no weight on the CE test because of the implementation problems of the CE test and the above-noted conceptual and methodological concerns with the CE test.

4.2.7 Other Measures of Comparable Investment

Although the Board will not place any weight on the CE test, the Board considers that there may be other measures of comparable investment that should be considered in the establishment of an appropriate ROE. In this section, the Board will address other such measures of comparable investment that were raised in the Proceeding.

Return Awards for Other Canadian Utilities

The Board acknowledges the potential for circularity when considering awards by other regulators. Nevertheless, the Board considers that awards by other Canadian regulators may provide some indication of the appropriate ROE for the Applicants.

[61] Calgary/CAPP Argument, page 6

Dr. Evans provided, at the Board's request, a detailed compilation of ROE awards and other matters for Canadian utilities.[62] The following table is an excerpt from that compilation:

Table 5. Awarded ROEs for Other Canadian Utilities

	Date	Awarded ROE (%)
British Columbia		
Aquila Networks Canada (BC) Ltd.	November 2003	9.55
Pacific Northern Gas Ltd.	November 2003	9.90
Terasen Gas Inc.	November 2003	9.15
Ontario		
Enbridge Gas Distrbution	November 2003	9.69
Union Gas Ltd.	Jan. 1999/July 2001	9.95
Quebec		
Gaz Metropolitain	September 2002	9.89
Nova Scotia		
Nova Scotia Power Inc.	October 2002	10.15
Prince Edward Island		
Maritime Electric	October 2001	11.00
Newfoundland		
Newfoundland Power Inc.	June 2003	9.75
National Energy Board	November 2003	9.56

Directionally, the evidence on recent awards for other Canadian utilities would support a 2004 ROE above the Board's CAPM estimate. However, the Board concludes that limited weight should be placed on this evidence due to the potential for circularity.

Return Awards for U.S. Utilities

The Applicants generally took the view that it is appropriate to consider utility ROEs awarded by U.S. regulators, due to the similarity between Canadian and U.S. utilities and due to the high degree of integration of the capital markets of the two countries.

The Board notes the evidence of various Applicants that low risk gas distribution utilities in the U.S. have allowed returns in the 11% range on a 45% common equity component, and that prior to incentives, the base return for interstate electric transmission companies allowed by FERC is in excess of 12% on a 50% equity component.[63]

The Board also notes the submissions of various interveners that there are several differences between Canadian and U.S. regulation. The Board, in particular, notes CAPP's submission that U.S. pipelines operate under a regulatory regime that has exposed them to severe realized and potential risks. In this regard, the Board notes the evidence[64] of CAPP indicating low actual returns of a number of U.S. interstate pipelines.

62 Exhibit 021-24
63 ATCO Argument, pages 29-30
64 Exhibit 015-11, Written Evidence of CAPP, pages 49-50

In the Board's view, the Applicants did not demonstrate that the regulatory regimes in the two countries are sufficiently comparable that the Board should place significant weight on the return awards for U.S. utilities. For example, the Board notes differences in legislation, public and regulatory policies, the higher prevalence of longer-term settlement arrangements, the federal/state jurisdictional divisions, the development of RTOs and other differences in the structure of regulated industrial sectors, and differences in national fiscal, tax and monetary policies. The Board notes AltaLink acknowledged that there are some differences in the Canadian and U.S. electric industry structures that may impact some of the higher return and equity component awards in the U.S.[65]

Furthermore, the Board notes the recent acquisitions, at premiums to book value, by U.S. companies of an interest in TransAlta Corporation's former distribution and transmission businesses. The Board considers these acquisitions, which are discussed further below, may be an indication that the regulated returns available in Alberta are not too low for U.S. firms, relative to investment opportunities in their home country given all relevant circumstances.

Directionally, the evidence on the awards available to U.S. utilities would support a 2004 ROE above the Board's CAPM estimate. However, the Board concludes that limited weight should be placed on this evidence due to the differences in the regulatory, fiscal, monetary, and tax regimes in the two countries.

FERC Incentives for Transmission Facilities

A number of the applicants suggested that if the Board did not reflect the incentive awards that FERC has in place for new electric transmission facilities, then capital might not be available for utility infrastructure in Alberta. These applicants argued that above-market ROEs would be in the public interest in order to ensure that sufficient capital is attracted for Alberta's infrastructure needs.

The Board is not persuaded that the existence of certain FERC-regulated transmission projects with allowed returns above the current market required rate of return would impair the ability of Alberta utilities to attract capital. In the Board's view, Alberta utilities do not compete for capital only with these projects, but rather with a broad universe of investment opportunities. Furthermore, if the higher allowed returns for these projects were material to the Canadian market required return, the Board considers that the impact of these higher allowed returns would already be reflected in the Canadian market required return.

Furthermore, the Board notes that the FERC incentives are intended to encourage RTO participation, independent ownership of transmission facilities, and investment in new facilities found appropriate pursuant to an RTO process. The Board notes that the objectives of encouraging RTO participation and encouraging independent ownership of transmission facilities are not applicable in Alberta. Similarly, the objective of encouraging investment in new independent transmission facilities into areas presently serviced by vertically integrated utilities is also not applicable in Alberta. Furthermore, the Board notes that both AltaLink and ATCO expressed continued strong interest in infrastructure development in Alberta.

The Board considers that there is no persuasive evidence in this Proceeding that demonstrates that above-market awarded returns are required to attract capital, and the Board notes that there

[65] AltaLink Specific Reply Argument, third page

is no evidence of any Alberta TFO having any difficulty in attracting capital to date. The Board considers that to award such returns in the absence of need would unnecessarily and inappropriately result in additional costs to consumers.

Furthermore, the Board considers that if it were satisfied in some future application that it was appropriate to award incentive returns to attract capital in connection with the construction of certain new electric transmission facilities in Alberta, such returns would not be appropriate on existing facilities and may not be necessary in respect of all new infrastructure developments.

The Board is not persuaded that there is any requirement at this time to offer above-market ROEs or other incentives to attract capital for the construction of new electric transmission facilities in Alberta. The Board will not put any weight on the FERC incentives for transmission facilities, for the purposes of determining the generic ROE.

Alliance and Maritime and North East Pipelines (M&NP)
NGTL's view was that Alliance and M&NP are particularly relevant comparisons for NGTL. NGTL noted that both Alliance and M&NP are regulated and ship into markets served by gas that moves through NGTL and TransCanada Pipelines Ltd. (TCPL)'s Mainline. NGTL submitted that Alliance and M&NP, as the most recent large greenfield pipelines, show what returns are necessary to entice investment in regulated natural gas pipelines. Alliance has an ROE of 11.25% on 30% deemed equity and M&NP has an ROE of 13% on 25% deemed equity.

In regards to the regulated returns of Alliance and M&NP, the Board agrees with CAPP that these returns are not directly relevant, due to different circumstances (such as the level of ROE being locked in for a long period of time) and because they date back to a period of higher interest rates and returns. In this respect, the Board notes CAPP's argument that Alliance takes risks that NGTL does not, including some volume risk on an exception basis, long-term shipper contract default risk, and long-term interest rate risk,[66] and that the M&NP was built for a new untested basin with few pools having been delineated. In addition, the Board notes that the deemed equity ratios for Alliance and M&NP are lower than any Board-approved equity ratio, which would directionally reduce the impact on customer rates of a higher ROE.

Although, directionally, the absolute level of return for Alliance and M&NP would support a 2004 ROE above the Board's CAPM estimate, the Board concludes, based on the above analysis, that it should place limited weight on the Alliance and M&NP returns.

Market-to-Book Ratios and Acquisition Premiums
The Board notes the evidence, including that of AltaGas[67] and Calgary/CAPP[68] that the equity of utilities that earn a large portion of their earnings based on regulated formulas in other Canadian jurisdictions tends to trade at market-to-book ratios well above 1.0, albeit at premiums less than the average market premium.

The Board also notes that there have been a number of acquisitions of Alberta utilities in recent years, at prices that significantly exceeded book value. For example, in 2000, Aquila acquired TransAlta Corporation's distribution and retail businesses at a total price of 1.5 times book value. Book value was forecast to be $472 million at time of close, resulting in a forecast premium of

66 Exhibit 015-11 Written Evidence of CAPP, page 36 and 49
67 AltaGas Argument, page 24
68 Exhibit 016-11(b), Written Evidence of J.D. McCormick, page 5

$238 million.[69] Aquila subsequently sold TransAlta's former retail business to EPCOR Energy Services (Alberta) Inc. for $110 million, including a premium of $99 million.[70]

As well, in 2004, Fortis purchased Aquila for a premium of $215 million above the book value of $601 million.[71]

Similarly, with respect to the AltaLink acquisition of TransAlta Corporation's transmission assets, the Board notes Mr. McCormick's[72] evidence that a premium of $200 million was paid to acquire a rate base of approximately $644 million.

The Board agrees with the Applicants that there are a number of factors impacting market-to-book ratios of utility holding companies and that one has to be cautious making inferences regarding the regulated utilities. The Board also agrees that there may be strategic factors affecting the price that is paid to acquire a utility.

For example, NGTL submitted that its parent did not acquire a further interest in the Foothills pipeline, paying 1.6 times book value, for the opportunity to earn a return at the NEB formula rate; rather, the investment was made in an effort to increase the probability that TCPL will participate in a Northern pipeline project. The Board also recognizes that, in some cases, a premium might be paid for regulated assets in anticipation of significant future growth in rate base, to achieve geographic diversification or to obtain a foothold in a new market. However, parties are also aware of the constraints placed on regulated utilities with respect to affiliate transactions, particularly those with unregulated affiliates.

In the absence of such strategic factors, the Board would not expect a prudent investor to pay a significant premium unless the currently awarded returns are higher than that required by the market. The Board acknowledges the views of some parties that payment of a premium over book value for a regulated utility indicates that the recent ROE awards may have been higher than required by the market. The Board is not aware of the strategic factors that may have affected the price paid to acquire Alberta utilities in recent years. Nevertheless, the experience regarding the market-to-book values of utilities and the experience regarding the acquisition of Alberta utilities in recent years gives the Board some comfort that its recent ROE awards have not been too low.

Further in this regard, the Board notes AltaLink's testimony, in response to examination by the Chairman,[73] that AltaLink's decision to purchase TransAlta's transmission business considered Board awards for transmission entities of 9.75% ROE on a capital structure including 35% equity.

Directionally, the Board concludes that the experience regarding the market-to-book ratios of utilities and the experience regarding the acquisition of Alberta utilities in recent years is relevant and supports continuation of an ROE at or below the Board's CAPM estimate.

[69] Decision 2000-41, page 3
[70] Decision 2000-71, page 3
[71] Decision 2004-035, page 18
[72] Exhibit 016-11(b) Evidence of J.D. McCormick, pages 39-40
[73] Transcript, Volume 15, pages 2004-2006

Income Trusts

The Board notes the significant disagreement among parties with respect to return expectations of investors in Income Trusts. The Board notes that Mr. McCormick relied primarily on a sample of only five Income Trusts and that the validity of his sample selection was the subject of substantial debate.

In the Board's view, the theoretical return, indicated by Mr. McCormick, based on ROE does not address actual investor expectations on investment or actual historic returns on investment of Income Trust investors. For example, the Board notes that Income Trust prices often rose despite the fact that part of the distributions represented return of capital.

The Board generally agrees with the views of the Applicants that Income Trusts may be overvalued[74] due to investors' misperceptions and may be too new to be a reliable indication of required market returns. The Board also does not consider that there is any evidence that the allegedly lower return requirements for Income Trusts are achievable in a corporate structure. The Board notes that no party advocated that the Applicants be required to reconstitute as Income Trusts. The Board also notes that some Income Trusts have much higher equity ratios than the Applicants, which would directionally offset the impact of a lower ROE on customer rates.[75]

Nonetheless, the Board notes that Income Trusts are attracting a substantial amount of new capital.

Directionally, the Board considers that the experience with Income Trusts would support an ROE at or below the Board's CAPM estimate. However, for the reasons cited above, the Board concludes that limited weight should be placed on this experience.

Pension Return Expectations

Interveners generally took the position that TCPL's forecast pension return on Canadian equity investments of 9.5% was an indicator of the Canadian market return expected by TCPL. NGTL argued that the forecast of 9.5% was prepared by its actuaries and was not comparable to an investment hurdle rate. NGTL further argued that the forecast of 9.5% was a geometric estimate rather than an arithmetic estimate.

The Board acknowledges that forecast pension returns on equity investments may be conservative by their nature, but the Board nevertheless considers that forecast pension returns on equity investment are a valid indicator, albeit potentially conservative, of the forecaster's current market equity return expectation. However, the Board agrees with NGTL that the forecast pension return is akin to a geometric average and would therefore understate the forecaster's short-term expectation for the market return. Directionally offsetting this impact, the Board would expect the required return for utilities to be below the required overall equity market return.

On balance, the Board concludes that the evidence on forecast pension returns would support a modest increase from the Board's CAPM estimate.

[74] NGTL Argument, page 105-107; ATCO Argument, page 43
[75] NGTL Argument, page 107

Other Investment Alternatives Available To Utility Shareholders

The Board notes NGTL's evidence that its parent, TCPL, has other investment alternatives, such as unregulated power generation projects, that earn a return higher than the return allowed for NGTL. NGTL also argued that TCPL has the option of making investments at higher returns in the U.S. and repatriating the profits to Canadians via the dividend tax credit. NGTL submitted that it requires a higher return in order to compete with these other investment opportunities of TCPL.

The Board agrees with the interveners[76] that NGTL's evidence regarding earnings on power generation projects were merely forecasts of earnings, and represented a limited and select sample. The Board also notes that NGTL did not supply any evidence that evaluated historical returns from other investments versus returns from its Canadian utility investments, which is one relevant factor to be considered when making prospective investment decisions.

The Board concludes that there is no basis on which to place any weight, other than already reflected in earlier tests, on other specific investment opportunities potentially available to utility investors or on stated expectations of return from such opportunities.

4.2.8 2004 ROE

The Board found above that a reasonable CAPM estimate for 2004 is 9.20%. The Board considers that it is appropriate to assess the results of other tests to determine if the 2004 ROE should be above or below the CAPM estimate.

The Board found above that the following evidence would generally support a 2004 ROE at or below the CAPM estimate:

1. Market-to-Book Ratios and Acquisition Premiums
2. Income Trusts

Similarly, the Board found above that the following evidence would generally support a 2004 ROE at or above the CAPM estimate:

1. ERP Tests Other Than CAPM
2. Return Awards for Other Canadian Utilities
3. Return Awards for U.S. Utilities
4. Alliance and M&NP
5. Pension Return Expectations

As discussed above, the Board did not put any weight on the following evidence in determining whether the 2004 ROE should be above or below the CAPM estimate:

1. Discounted Cash Flow Test
2. Comparable Earnings Test
3. FERC Incentives for Transmission Facilities
4. Other Investment Alternatives Available to Utility Shareholders

[76] Cargill Argument page 22 and CAPP Argument page 23

In the next section of this Decision, the Board establishes an adjustment mechanism that includes an adjustment factor of less than 100% of the change in the long-Canada yield, which in the Board's view also supports a 2004 ROE above the CAPM estimate since the allowed ROE will not reflect a 100% adjustment factor, which is implicitly suggested by CAPM, and since a formulaic approach effectively creates a longer test period with respect to ROE.

In consideration of the impact of the above factors, it is the judgment of the Board that it would be appropriate to establish the 2004 ROE at a level that is 40 basis points above the Board's CAPM estimate. Therefore, the Board concludes the generic ROE for 2004 should be set at 9.60%.

4.3 Annual Adjustment Mechanism

As outlined earlier in this Decision, the Board will now address the potential use of an adjustment mechanism for ROE.

The following table summarizes the positions of the parties:

Table 6. Annual Adjustment Mechanism Recommendation by Parties

Party	Annual Adjustment Mechanism Recommendation
AltaGas/ATCO	50% of long-Canada bond yield change
Companies	75% of long-Canada bond yield change
ENMAX	100% of long-Canada bond yield change plus 100% of utility bond spread change
NGTL	Link to changes in Corporate bond yields
Calgary/CAPP	75% of long-Canada bond yield change
Cargill	75% of long-Canada bond yield change (80% or 100% also acceptable)
CG	75% of long-Canada bond yield change plus 50% of market dividend yield change
IPCAA	75% of long-Canada bond yield change

The Board notes that most parties favored an adjustment formula with the ROE changing by 75% of the change in the forecast long-Canada bond yield, provided that the Board accepted their starting positions on ROE.

The Board also notes Dr. Evan's evidence that a change based on 75% of the change in the long-Canada bond yield is driven by the differential tax rates between bonds and equity.[77]

The Board notes ATCO's and ENMAX's concern that it would be unfair to set an initial ROE based strictly on a CAPM analysis and to then allow only 75% of any increase in the long-Canada bond yield. In such a situation, ATCO and ENMAX favoured a 100% adjustment. The Board notes that in the previous section of this Decision, the Board established a generic ROE for 2004 of 9.60%, a level that is 40 basis points above the Board's CAPM estimate of 9.20%.

The Board does not consider that ENMAX's proposal to adjust the ROE by the sum of the change in the long-Canada bond yield and the change in the utility bond spread to be appropriate due to the difficulty of determining and tracking bond yields for a representative sample of corporate bonds.

[77] Companies Argument, page 89

The Board also does not consider CG's proposal to adjust the ROE by the sum of 75% of the change in the long-Canada bond yield and 50% of the change in the market dividend yield to be appropriate because of potential double-counting and because independent forecasts of dividend yields are not readily available in the same manner as the Consensus Forecast for debt.

The Board notes the Companies' proposal that the adjustment formula not commence until the year 2006. The Board notes that no other party proposed that implementation of an adjustment formula not commence until the year 2006. The Board does not consider that there is any reason to delay implementation of the adjustment formula until 2006.

Considering all of the above, the Board concludes that an adjustment to the generic ROE based on 75% of the change in long-Canada bond yield would be appropriate, beginning in 2005.

The Board considers the formula proposed by Dr. Evans (sponsored by the Companies) to be an appropriate method of implementing this adjustment:

$$ROE_t = 9.60\% + [0.75 \text{ x } (YLD_t - 5.68\%)]$$

where YLD_t = the forecast long-term Canada bond yield for year t.

Consistent with the approach used by the NEB, the forecast long-term Canada bond yield for year *t* shall be calculated as the average of the 3-month-out and 12-month-out forecasts of 10-year Canada yields as reported in the Consensus Forecasts[78] issue in November of the previous year, plus the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October in the previous year, as reported in the National Post.

[78] Consensus Forecasts Inc., London, England

4.4 Process to Review ROE

The following table summarizes the review process recommendations of the parties:

Table 7. Process to Review ROE – Recommendations by Parties

Party	Periodic Review	Other Review Triggers
AltaGas/ATCO	Review in 2007	• Long-Canada yield below 4% or above 8%. • A-rated utility bond spreads exceed 50% of the generic risk premium.
Companies	5 years	
ENMAX	Not more than 3 years	• Any Alberta utility is downgraded by a rating agency. • Formula result rises or falls more than 200 basis points from initial level.
NGTL	2 years	
Calgary/CAPP	5 years	• Long-Canada bond yield changes by more than 3.0%.
Cargill	3 to 5 years	
CG	3 years for the first review; 5 years thereafter	• Material change in investment risk of the regulated sector. • Material change in the market equity risk premium.
IPCAA	5 years	
IPPSA	5 years	

In the Board's view, it would be appropriate to trigger a review of whether the adjustment mechanism continues to yield a fair ROE, if there is a material change in the forecast long-Canada bond yield from the November 2003 forecast.

The Board considers that the most straightforward method of implementing this trigger is by placing bounds on the range of ROEs that can be established pursuant to the adjustment mechanism.

In this regard, the Board considers ENMAX's proposed change of 200 basis points in the generic ROE to be a reasonable trigger. The Board notes that a change of 200 basis points in the generic ROE is equivalent to a change of 267 basis points in the long-Canada bond yield, which is effectively higher than the long-Canada bond yield trigger proposed by ATCO but lower than the long-Canada bond yield trigger proposed by Calgary/CAPP.

Therefore, if the ROE resulting from the adjustment mechanism results in an ROE of less than 7.6% or greater than 11.6%, the Board will seek the views of parties on whether the adjustment mechanism continues to yield a fair ROE in the manner described below.

The Board considers that ATCO's proposed trigger of A-rated utility bond spreads exceeding 50% of the generic risk premium would be difficult and contentious to implement, principally due to controversy in the choice of the sample of utility bonds.

The Board does not consider ENMAX's proposed automatic trigger of any Alberta utility downgraded by a rating company to be appropriate because of the many factors and judgments that may contribute to a downgrade for an individual company, including their unregulated business results.

The Board considers that CG's proposed triggers of a material change in the investment risk of the regulated sector or a material change in the market risk premium would be difficult and contentious to implement. The Board considers that material changes in investment risk of the regulated sector or in the market risk premium can be addressed at the time of the periodic review.

The Board notes that all parties agreed that a review of whether the adjustment mechanism continues to yield a fair ROE should be conducted after a defined period of time. The Board notes that the time period for a review suggested by the parties varied from 2-5 years.

The Board considers that a review period of 5 years would appropriately balance the desire to achieve regulatory efficiencies through the use of an adjustment mechanism and the need to ensure that the ROE adjustment process continues to result in an appropriate ROE.

In the Board's view, triggering an early consideration on whether or not to conduct a review if the ROE resulting from the adjustment mechanism is less than 7.6% or greater than 11.6% also supports the selection of a five year review period.

The Board notes the Companies' proposal of a *de novo* review of all cost of capital matters at the end of five years. However, the Board does not consider that it would be appropriate to automatically trigger a *de novo* review either in the event that the adjustment mechanism results in a ROE of less than 7.6% or greater than 11.6% or at the end of five years, without first assessing whether the adjustment mechanism continues to yield an appropriate ROE result.

Therefore, the Board will first seek the views of parties on the preliminary question of whether the adjustment mechanism continues to yield a fair ROE prior to the establishment of the common ROE for the year 2009, or earlier if the ROE resulting from the adjustment mechanism for years prior to 2009 is less than 7.6% or greater than 11.6%. The Board will consider the views of parties on this preliminary question before deciding whether to undertake a general review of ROE or of the adjustment mechanism.

The Board notes that any party, at any time, will be free to petition the Board to consider a review of the adjustment formula, or to exempt a particular party from its application. The Board agrees with the submissions of the Companies,[79] Calgary/CAPP,[80] and IPCAA[81] that there would be an element of judgment involved in determining whether circumstances have changed sufficiently to warrant review, and that the ROE and adjustment mechanism determined by the Board should be entitled to a presumption of reasonableness, with any party seeking early review or an exemption bearing the onus of demonstrating that circumstances have rendered them unreasonable. The petitioning party would bear the onus of demonstrating a material change in facts or circumstances from the evidence filed in this Proceeding to merit a review of the adjustment formula or an exclusion from the formula.

[79] Companies Argument, page 92
[80] Calgary/CAPP Argument, pages 23 and 64 (the later regarding capital structure)
[81] IPCAA Argument, page 24

5 CAPITAL STRUCTURE

5.1 Introduction

The Board notes that the capital structures determined in this Proceeding are premised on the business risks that existed at the time of the Proceeding.

For the convenience of readers, the following table (ordered by sector) compares the equity ratios that were last approved by the Board with the equity ratios recommended by the Applicants, CG and Calgary/CAPP:

Table 8. Recommended Equity Ratios vs. Last Board Approved Equity Ratios

	Last Board-Approved (%)	Recommended by Applicant (%)	Recommended by CG (%)	Recommended by Calgary/CAPP (%)
Electric and Gas Transmission				
ATCO Electric TFO	32.0	38.0	30.0	30.0
AltaLink	34.0[4]	37.5	30.0	32.0
EPCOR TFO	35.0	40.0	30.0	35.0
NGTL	32.0	40.0	32.0	33.0
ATCO Pipelines	43.5	50.0[3]	40.0	38.0
Electric and Gas Distribution				
Aquila	N/A [1]	42.5	35.0	35.0
ATCO Electric DISCO	35.0	45.0[2] (+ 5-10 %)	35.0	35.0
ENMAX DISCO	N/A [5]	50.0	35.0	40.0
EPCOR DISCO	N/A [5]	45.0	35.0	40.0
ATCO Gas	37.0	40.0	37.0	35.0
AltaGas	41.0	45.0	40.0	35.0

1 The Board did not specifically approve this ratio; it was part of a negotiated settlement approved in Decision 2003-019, which included a deemed 40% equity ratio as one of many settled parameters of the revenue requirement.
2 ATCO Electric DISCO requested a further increase of 5-10%, beyond its original request of 45%, in its equity ratio to account for ATCO's perception of additional business risks resulting from the *RDS Amendment Regulation.*[82]
3 ATCO Pipelines, in addition to a 50.0% equity ratio, also proposed a 0.5% addition to ROE.
4 In Decision 2003-061, the Board approved an equity ratio for AltaLink of 32%, plus an additional 2% to offset the impact on the interest coverage ratio of a partial allowance of income taxes in the revenue requirement.
5 ENMAX and EPCOR Distribution were subject to Board jurisdiction effective January 1, 2004.

The Board notes that, with the exception of CGA, the interveners who did not sponsor expert evidence generally supported the views of CG and Calgary/CAPP in argument. The Board also notes that the Applicants did not generally take a position on the appropriate capital structures for other Applicants.

In the Board's view, setting an appropriate equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk.

82 *Regulated Default Supply Amendment Regulation* (AR 323/2003)

To determine the appropriate equity ratio for each Applicant, the Board will consider the evidence and, where applicable, the experts' views and rationales in each of the following topic areas:

1. The business risk of each utility sector and Applicant;
2. The Board's last-approved equity ratio for each Applicant (where applicable);
3. Comparable awards by regulators in other jurisdictions;
4. Interest coverage ratio analysis; and
5. Bond rating analysis.

The Board notes the general consensus that the electric and gas transmission sectors had the least risk of all Applicants in this Proceeding. Further, the Board notes that no party argued otherwise.

The Board will first consider the appropriate capital structures for the electric and gas transmission Applicants, and the Board will subsequently consider the appropriate capital structures for the electric and gas distribution Applicants.

5.2 Electric and Gas Transmission

The Board notes from the above Table 8 that for the taxable electric transmission companies,[83] the Applicants proposed equity ratios of 37.5 and 38.0%, whereas the interveners proposed an equity ratio of 30.0%.

With respect to transmission companies that are not fully taxable, the Board will provide its findings later in this Decision.

With respect to gas transmission, NGTL proposed an equity ratio of 40%, while the interveners proposed 32 and 33%. The equity ratios proposed by all submitting parties for ATCO Pipelines were materially higher than the equity ratios each proposed for NGTL. The Board will address ATCO Pipelines later in this Decision.

Business Risk

The Board notes that the Companies[84] compared the risks of electric transmission companies with the risks of NGTL as they existed in 1995. Dr. Evans (sponsored by the Companies) considered that electric transmission companies have more risk today than NGTL had at the time NGTL's equity ratio was last approved, for 1995.[85]

However, the Board considers that because it now has evidence regarding all Applicants' current risks, the utilities should be compared based on the business risks that existed at the time of this Proceeding. This was the approach of the experts other than Dr. Evans.

ATCO submitted that electric transmission companies were more risky than NGTL, principally due to the smaller size of the electric transmission companies relative to NGTL, the higher expected growth rates of the electric transmission companies relative to NGTL, and ATCO's

83 In this Proceeding, AltaLink assumed it was fully taxable, but the Board did not.
84 Companies Argument, page 96
85 Companies Argument, page 98

perception of a greater degree of regulatory uncertainty for the electric transmission companies relative to NGTL.

Although NGTL did not compare its level of business risk to that of other utilities, it did submit extensive evidence with respect to its own business risks, including operating expense risk, supply risk, competition risk, volume risk and credit risk.

Calgary/CAPP[86] and CG[87] each considered NGTL to have higher short and long-term business risk than the electric transmission companies, because NGTL faces operating expense risk, supply risk, competition risk, volume risk and credit risk, whereas the electric transmission companies only face operating expense risk. The interveners[88] viewed TFO growth prospects as an opportunity rather than a risk.

The Board agrees with the interveners that NGTL has a higher short-term business risk than the electric transmission companies, principally due to higher competition and credit risks. The Board also considers that NGTL potentially faces higher long-term risks due to supply risk although, in the Board's view, the bulk of that risk, if it materializes, will likely be identified early enough for NGTL to apply to the Board for potential adjustments to throughput forecasts and/or depreciation rates.

The Board also notes that NGTL does not have the same revenue certainty, as do the electric transmission companies. The Board also considers the higher expected growth rates of the electric transmission companies to be an opportunity for the TFO shareholders to increase their investments, and not fundamentally a matter of increased risk. The Board notes that utilities are allowed a return on funds used during construction. In addition, the Board was not persuaded that electric transmission companies have a greater degree of regulatory uncertainty than gas transmission companies.

The electric transmission companies have a single customer, the AESO. The Board considers the AESO to be of minimal credit risk. Further, the Board notes that the AESO pays the electric transmission companies 1/12 of their approved revenue requirement on a monthly basis with no adjustment for changes in demand or supply of electricity carried by the TFO.

For all of the above reasons, the Board does not agree with ATCO and the Companies that the electric transmission companies are more risky than NGTL.

The Board concludes that taxable electric transmission companies have the lowest business risk of any utility sector regulated by the Board, and that the risks of NGTL are somewhat higher than the risks of a fully taxable electric TFO.

The Board notes, from the above Table 8, that CG's and Calgary/CAPP's recommended equity ratios for NGTL were 2% and 3%, respectively, higher than their recommended equity ratio for a fully-taxable electric TFO. The Board also notes that NGTL did not provide the Board with an indication of its views respecting its risks relative to electric transmission companies, and, more particularly, did not indicate a view on an appropriate equity ratio differential compared to electric transmission companies.

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86 CAPP/Calgary Argument, page 56
87 CG Argument, pages 67-70
88 CG Argument, page 70; Calgary/CAPP Argument, pages 67-70

The Board considers that business risk, in isolation, would indicate an equity ratio for NGTL that is 2-3 % higher than the equity ratio for a fully taxable TFO.

Comparison to Previous Board Awards

The Board notes that the last Board-approved equity ratio for NGTL of 32% was established for 1995.[89] The Board agrees with the general view of the experts that the business risks of NGTL have increased since 1995, principally due to a potentially higher supply risk and a higher competition risk.

Directionally, the Board concludes that NGTL's higher business risk, in isolation, supports an equity ratio for NGTL higher than 32%.

In Decision U99099, the Board established an equity ratio for electric transmission companies (TFOs) of 35%. In Dr. Evan's view,[90] the risks of electric TFOs have not changed since the time of Decision U99099, which would indicate that no change in equity ratio was appropriate. However, the Board considers that the risks of electric transmission companies have likely decreased since the time of Decision U99099 due to increased clarity of the role of the TFO, increased clarity with respect to the AESO's role and structure, the resolution of liability issues and the changes in transmission policy including the role of competitive bidding.

Directionally, the Board considers that this factor, in isolation, supports an equity ratio for fully taxable electric transmission companies lower than the 35% determined in Decision U99099.

The Board notes the last approved equity ratio for ATCO Electric TFO was 32% and for AltaLink was 34% (32% + 2% for the interest coverage ratio adjustment). However, these ratios were established when NGTL's award was 32%.

Directionally, the Board considers that this factor, in isolation, supports an equity ratio for fully taxable electric transmission companies similar to the last award of 32% or marginally higher.

Comparable Awards by Regulators in Other Jurisdictions

The Board acknowledges the potential for circularity when considering awards by other regulators. The Board also recognizes that business risks may be quite different in other jurisdictions. The Board has discussed some of these differences in the ROE section of this Decision and will provide further comment in following sections of this Decision. Nevertheless, the Board considers that comparable awards by other regulators may provide some indication of the appropriate capital structures for the Applicants.

As a result of the electric industry restructuring in Alberta, the Board notes that there are no TFO entities in the other provinces of Canada that are directly comparable to TFO entities in Alberta. However, in the Board's view, Canadian federally regulated natural gas transmission pipelines are of some assistance in drawing comparisons to both NGTL and the taxable electric transmission companies.

89 U96001, Nova Gas Transmission Ltd., 1995 General Rate Application, Phase 1
90 Companies Argument, page 110

The Board considers that the nature of NGTL as a gathering system, with numerous receipt and delivery points, a diverse customer base, and other related factors demonstrates an additional degree of business risk for NGTL when compared to the TCPL Mainline. However, the breadth of NGTL's diverse customer base mitigates the additional risk to a large degree, since the loss of any one customer or point of supply would likely not be material to the long-term risks faced by NGTL. The Board notes that in RH-4-2001, dated June 2002, the NEB awarded TCPL's Mainline a 33% common equity ratio based on its conclusion that "the level of business risk facing the Mainline has increased since 1995…".[91] The NEB cited "increases in the risks resulting from pipe-on-pipe competition and increased supply risk but noted, "other sources of risk have not changed materially".[92]

The Board notes that NGTL's last awarded equity ratio of 32% for 1995 was 2% higher than the contemporaneous NEB award of 30% for TCPL's Mainline. The Board notes that the same 2% differential if applied today would result in an equity ratio of 35% for NGTL. The Board considers that this factor, in isolation, supports an equity ratio of 35% for NGTL.

Since the Board considers electric transmission companies to have less risk than NGTL, the Board considers that this factor, in isolation, supports an equity ratio of less than 35% for taxable electric transmission companies.

The Board notes Dr. Evan's evidence,[93] provided at the Board's request, that the awarded equity ratios for the Foothills, ANG and TQM pipelines remain at the 30% level that the NEB established in 1995.

However, the Board notes the NEB's view[94] that Foothills and ANG operated on a lower risk monthly cost of service basis, and that TQM had a high degree of assurance that its costs would be recovered. For these reasons, the Board considers the risks of the taxable electric transmission companies and NGTL are somewhat higher than the risks of Foothills, ANG and TQM. Consequently, the Board considers that this factor, in isolation, supports an equity ratio of more than 30% for both the taxable electric transmission companies and NGTL.

The Board notes that the awarded equity ratio of the Westcoast Energy pipeline remains at 35%, which was set by the NEB in 1995. The Board also notes the NEB's view[95] that Westcoast had higher risks due to the nature of its gathering system and processing plants and due to the hydrogen sulfide content of the gas it transports. For these reasons, the Board considers the risks of taxable electric transmission companies to be lower than the risks of Westcoast and the Board considers the risks of a large gathering system like NGTL to be more similar to Westcoast than to the electric transmission companies. Consequently, the Board considers that this factor, in isolation, supports an equity ratio of approximately 35% for NGTL and less than 35% for the taxable electric transmission companies. However, the Board would note that there are also differences between Westcoast and NGTL.

91 RH-4-2001, page 58
92 RH-4-2001, page 28
93 Exhibit 021-24
94 RH-2-94, page 26
95 RH-2-94, page 25

Interest Coverage Ratio Analysis

The Board notes that S&P provides guideline interest coverage ratios,[96] corresponding to various corporate credit ratings, for utilities of various business risk profiles (risk ranking levels). The Board further notes ATCO's evidence[97] that the estimated S&P risk ranking for ATCO Electric transmission is "2" and that the actual S&P business risk profile ranking for NGTL is "3".

The S&P guidelines indicate that for a utility with a risk ranking of "2", a pretax interest coverage ratio in the range of 2.3 to 2.9 times is indicated for an "A" debt rating.

The Board notes that S&P does not rigorously apply its guidelines with respect to each specific financial ratio. In addition to interest coverage ratios, S&P reviews a number of other key financial ratios, as well as many diverse and often subjective factors, in order to arrive at a specific credit rating for an individual utility.

The Board notes that Enbridge Gas has been assigned a risk ranking of "2", which would imply that electric and gas transmission companies, which are less risky, could be considered to be ranked at less than "2".

The Board does not have a target credit rating for utilities under its jurisdiction. The Board is of the view, however, based on the evidence before it in this Proceeding, that interest coverage ratios and credit ratings are important considerations in assessing the appropriate capital structure. However, the Board considers that the foregoing are just one set of factors to consider.

The Board notes that DBRS has indicated, in its NGTL credit rating report,[98] that an interest coverage ratio "above 2 times … is acceptable for a regulated cost of service-based business".[99] The Board notes that the DBRS report, "Methodologies in Rating Utilities", dated June 2002,[100] indicates a fixed-charge coverage ratio of 1.5 for a DBRS debt rating from BBB to A. The report's definition of fixed-charge coverage, in cases where preferred shares do not exist, is the same as the definition of interest coverage that the Board has used throughout this Decision. The Board notes the apparent inconsistency in the two statements, but considers that taken together, a conclusion can be drawn that an interest coverage ratio near 2 times might be appropriate for low risk regulated entities. The Board also notes Dr. Booth's (sponsored by Calgary/CAPP) evidence that an interest coverage ratio of 2.15 times is reasonable for pipelines, considering their historic actual levels.[101]

The Board notes that some parties have expressed a concern that the acceptable equity ratios for regulated utilities in Alberta could potentially be overstated,[102] if the S&P guidelines with respect to interest coverage ratios were applied in a mechanical manner without consideration of other factors.

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96 Exhibit 008-02, pre-filed Information Response AUMA-AP-11
97 Exhibit 005-11-1, Capital Structures for the ATCO Utilities, Kathleen McShane, pages 9-11
98 Exhibit 013-17, DBRS credit rating report on NGTL, dated June 26, 2002, page 1
99 Exhibit 013-17, page 9 of 35
100 Exhibit 008-02, pre-filed Information Response CAL-AP-8
101 Exhibit 016-11(a), Evidence of L.D. Booth, page 63
102 Calgary/CAPP Argument, page 28

The Board has calculated the pretax interest coverage ratios that would result for a utility, with no preferred shares, using a 2004 tax rate of 33.87%,[103] using the ROE that the Board determined in this Decision of 9.6%, and applying a range of equity ratios and embedded debt costs. The Board will use the following table as one of several tests to evaluate and determine the appropriate common equity ratios.

The interest coverage ratio results for a range of equity ratios and embedded debt costs are as follows:

Table 9. Pretax Interest Coverage Ratios at Varying Embedded Debt Costs

Equity	Embedded Debt Cost					
Ratio	6.0%	6.5%	7.0%	7.5%	8.0%	8.5%
30.0%	2.0	2.0	1.9	1.8	1.8	1.7
31.0%	2.1	2.0	1.9	1.9	1.8	1.8
32.0%	2.1	2.1	2.0	1.9	1.9	1.8
33.0%	2.2	2.1	2.0	2.0	1.9	1.8
34.0%	2.3	2.2	2.1	2.0	1.9	1.9
35.0%	2.3	2.2	2.1	2.0	2.0	1.9
36.0%	2.4	2.3	2.2	2.1	2.0	2.0
37.0%	2.4	2.3	2.2	2.1	2.1	2.0
38.0%	2.5	2.4	2.3	2.2	2.1	2.0
39.0%	2.6	2.4	2.3	2.2	2.2	2.1
40.0%	2.6	2.5	2.4	2.3	2.2	2.1
41.0%	2.7	2.6	2.4	2.3	2.3	2.2
42.0%	2.8	2.6	2.5	2.4	2.3	2.2
43.0%	2.8	2.7	2.6	2.5	2.4	2.3
44.0%	2.9	2.7	2.6	2.5	2.4	2.3
45.0%	3.0	2.8	2.7	2.6	2.5	2.4

The above table shows the results of the mathematical calculations. The Board understands that bond ratings do not rely solely on precise mathematical results. Bond ratings incorporate a variety of factors, including the use of judgment.

The Board cautions readers not to interpret the level of precision expressed in the above table to be absolute in arriving at the appropriate equity ratio.

The Board is aware that some companies have higher embedded debt costs but these embedded debt costs are expected to decline as older, higher-cost debt is retired. The Board also notes that the embedded debt cost for AltaLink is lower than 6%, but that this embedded cost of debt could be understated since AltaLink's long-term financing does not appear to be fully in place.

The Board did not use the above table in a precise mathematical manner. Rather, the Board evaluates the data in the table above by looking at ranges, various company situations, longer-term effects, impacts of declining embedded costs, stability of capital structure awards as embedded debt costs change, and the consideration of other factors that are discussed in this Decision.

[103] 21% Federal rate, 1.12% surtax and 11.75% provincial tax (12.5% through March 31, 11.5% thereafter)

The Board further considers that all of these differing ratios are merely indicators in arriving at a level of coverage that is considered comfortable and acceptable.

Accordingly, based on the evidence and the above discussion, the Board concludes that an acceptable pretax interest coverage ratio for electric and gas transmission companies, in isolation, is near 2 times.

The Board considers that interest coverage ratio analysis, in isolation, supports equity ratios for taxable electric transmission companies and gas transmission companies greater than the currently approved equity ratios of 32% for ATCO Electric and NGTL.

The Board considers gas transmission companies to have slightly more risk than electric transmission companies and, therefore, the Board considers that this factor, in isolation, indicates that gas transmission companies should have slightly more equity than electric transmission companies.

Bond Rating Analysis

As noted above, the Board does not have a target credit rating for utilities under its jurisdiction. Further, the Board has discussed bond ratings, earlier in this Decision, in the context of the interest coverage ratios. Bond ratings are another factor in determining an appropriate capital structure.

With respect to the indications provided by actual bond ratings, Dr. Evans provided, at the Board's request, a detailed compilation of comparable equity ratios and bond ratings. The following table is an excerpt from that compilation, showing the awarded and the adjusted actual equity ratios for each utility regulated by the Board that has its own bond rating:

Table 10. Equity Ratios and Bond Ratings

	Last Board Awarded Equity (%)	Adjusted Actual Equity[104] (%)	DBRS credit rating[105] and deemed equity ratio at the same date (%)		S&P credit ranking and common equity ratio at the same date (%)	
AltaLink L.P.	34	38.3	A (high)	34.0[106]	A-	35 – 40 implied[107]
EPCOR Transmission	35	37	BBB (high) [108]	35.7[109]		
NGTL	32.2+0.3 preferred	40.3	A	38.9[110]	A-	36.0[111]
Aquila	40 (settlement)	41.9	A (low)	45.5 / 40.0[112]		

104 Exhibit 021-24 Dr. Evans calculated the most recently available Adjusted Actual Equity by treating short-term debt as debt, and by treating preferred shares and subordinated debt as 80% equity, consistent with the treatment described at page 106 of Decision 2003-061.

105 Source: Dr. Evans, Exhibit 021-24

106 Exhibit 021-45, AltaLink DBRS credit report, dated September 26, 2004, page 6

107 Exhibit 003-02-6, AltaLink S&P credit report dated May 16, 2003, page 4, indicates expected allowed equity of 35% and actual debt at 60-65% (implies actual equity of 35 to 40%).

108 Exhibit 012-03-h, DBRS letter regarding EPCOR Transmission Inc.'s indicative bond rating dated June 19, 2002

109 Exhibit 012-03-b, EPCOR Transmission Inc. Cost of Capital

110 Exhibit 021-43(c), beginning page 21 of 52, DBRS report on NGTL dated October 17, 2003, page 5

111 Exhibit 013-17, page 23 of 25, S&P report on NGTL dated June 19, 2003, page 3

Regarding EPCOR Transmission, the Board notes that the DBRS rating in the above table was only an indicative DBRS rating of BBB (high)[113] if DBRS had rated EPCOR in 2002, assuming no debt guarantee from the parent. The DBRS rating indication did not show the equity ratio used. However, the Board notes that an equity level of 35.7% for EPCOR Transmission was applicable[114] at the time that DBRS determined their bond rating to be BBB (high). The Board notes that the cost of debt has been declining since 2002[115] and as a result, the bond rating for a given equity ratio should improve as debt reaches maturity and is replaced. Consequently, the Board considers that this factor, in isolation, indicates that the equity ratio for EPCOR Transmission should be approximately 36%.

From the above table, the Board notes that AltaLink had DBRS and S&P credit ratings of A (high) and A- based on an equity ratio of 34% and a projected equity ratio of 35 to 40%, respectively. Furthermore, the Board notes that AltaLink has a substantial amount of goodwill on its books,[116] amounting to approximately 19% of its assets, which would require incremental equity support, compared to a TFO without goodwill. Consequently, the Board considers that this factor, in isolation, supports an equity ratio for AltaLink, based on rate base, somewhat below 34%.

The Board notes that NGTL has DBRS and S&P credit ratings of A and A- based on equity ratios of 38.9 and 36.0% respectively. In addition, the Board notes that the DBRS credit rating[117] of NGTL is partly based on its parent, TCPL. However, the Board notes that the S&P report[118] indicates that the credit rating is effectively that of TCPL, rather than that of NGTL itself. Therefore, in the Board's view, the adjusted actual equity ratio of NGTL may not be indicative of its required equity ratio, on a standalone basis.

Conclusion

At the beginning of this section, the Board indicated that it would consider a variety of factors for the electric and gas transmission companies.

As discussed in the preceding sections, in the Board’s view, setting an appropriate equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk.

The following table summarizes the indicated equity ratios that arise from various factors as discussed in the earlier sections.

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112 Exhibit 004-12, DBRS Report on Aquila, page 5, indicating 54.5% net debt at March 31, 2002 (implies 45.5% equity), and indicating 40.0% deemed equity at December 31, 2001

113 Exhibit 012-03-h, DBRS letter regarding EPCOR Transmission Inc.’s indicative bond rating dated June 19, 2002

114 Exhibit 012-03

115 Ibid.

116 Exhibit 021-45, AltaLink DBRS credit report, dated September 26, 2004, page 6

117 Exhibit 021-43(c), page 21 of 52, DBRS report on NGTL dated October 17, 2003, page 1

118 Exhibit 013-17, page 23 of 25, S&P report on NGTL dated June 19, 2003, page 1

Table 11. Indicated Common Equity Ratios for Transmission Companies By Factor

Factor	Indicated Electric Transmission	Indicated Gas Transmission
Business Risk	Lowest	TFO + 2-3%
Previous Board Awards	≥32%, <35%	>32%
Awards in Other Jurisdictions	>30%, <35%	~35%
Interest Coverage Ratio Analysis	>32%	>32%, >TFOs
Bond Rating Analysis	EPCOR ~36% AltaLink <34%	May not be indicative

After considering all of the above factors and after applying its judgment, the Board concludes that an appropriate common equity ratio for fully taxable electric transmission companies, with no preferred shares, is 33.0% and that an appropriate common equity ratio for gas transmission companies is 35.0%.

The Board will now consider each electric and gas transmission Applicant, individually.

5.2.1 ATCO Electric Transmission

The Board considers that ATCO Electric Transmission does not have any material differences in business risk from the typical TFO.

The Board also notes that ATCO Electric Transmission has preferred shares in its capital structure. Although the preferred shares provide additional support to the capital structure, in this analysis, the Board has evaluated the appropriate common equity ratio as if the company had no support from its preferred shares.

For the same reasons that were provided above, the Board concludes that an appropriate common equity ratio for ATCO Electric Transmission, a fully taxable TFO, is 33.0%.

The Board will further address the issue of ATCO's preferred shares later in this Decision.

5.2.2 EPCOR Transmission

The Board considers that EPCOR Transmission does not have any material differences in business risk from the typical TFO.

The Board therefore considers that any difference between the equity ratio for a fully-taxable electric TFO with no preferred shares and the equity ratio for EPCOR Transmission should only reflect the fact that EPCOR Transmission does not have any allowance for income taxes in its approved revenue requirement.

Dr. Evans (sponsored by the Companies, including EPCOR Transmission) recommended that non-taxable utilities be allowed an extra 2.5% equity. Dr. Evans argued that this additional equity component was warranted due to the generally lower interest coverage ratios and the greater variability of net income for non-taxable utilities.[119]

[119] Companies Argument, page 94

For similar reasons, Calgary/CAPP recommended that non-taxable entities be allowed an extra 5% equity.[120]

ENMAX argued[121] that its non-taxable status justified an additional 8% equity, based on the precedent established by the Board for AltaLink in Decision 2003-061.

All other parties who took a position, on the issue of non-taxable utilities, were of the view that no allowance for additional equity should be provided for non-taxable entities, principally due to a perceived offsetting benefit of lower, more competitive rates. ATCO argued that such an increment to the equity ratio would provide an inappropriate competitive advantage to non-taxable entities.

The Board agrees that a non-taxable entity has a higher volatility of earnings than an otherwise equivalent taxable company, arising from the lack of an income tax component in its forecast revenue requirement. The Board notes that there was no disagreement that the absence of taxation, while lowering costs, increases the volatility of earnings.

In the Board's view, arguments regarding the competitive advantage of non-taxable entities do not have persuasive merit in the context of regulated electric utilities, which do not compete with each other.

However, the Board is not persuaded that the higher volatility of earnings warrants an increase in the equity ratio as high as recommended above. The Board considers that an extra 2% equity would appropriately account for the higher business risks and earnings volatility of a non-taxable entity.

Adding the 2% increment to the 33% equity ratio determined above for a fully taxable TFO, the Board concludes that an appropriate common equity ratio for EPCOR Transmission is 35.0%.

5.2.3 AltaLink

The Board considers that AltaLink does not have any material differences in business risk from the typical TFO.

The Board therefore considers that any difference between the equity ratio for a fully-taxable TFO with no preferred shares and the equity ratio for AltaLink should only reflect the differences in the amount of income taxes included in the respective revenue requirements.

The Board notes that in Decision 2003-061, the Board allowed an additional 2% on the equity ratio to recognize the disallowance of 25% of the requested income taxes, bringing the total common equity component to 34%. The additional 2% equity was intended to maintain the same interest coverage ratio as if there had been no disallowance of income taxes. The Board recognizes that a review and variance application with respect to Decision 2003-061 is pending.

The Board notes the adjustment to AltaLink's equity ratio was intended to maintain the same interest coverage ratio as if there had been no disallowance of income taxes, whereas the purpose of the adjustment to the equity ratios of the municipally owned utilities in this Decision is to

[120] Calgary/CAPP Argument, page 59-60
[121] ENMAX Argument, page 36

appropriately account for their higher volatility of earnings. The Board considers these two situations to be fundamentally different.

The Board notes that no party addressed the appropriate adjustment to AltaLink's equity ratio to reflect the partial disallowance of income tax. Assuming that the Board's disallowance of 25% of the requested income taxes is continued, the Board considers that it would continue to be appropriate to adjust AltaLink's equity ratio to maintain the same interest coverage as if there had been no disallowance of income taxes.

Adding the 2% adjustment to the 33% equity ratio determined above for a fully taxable TFO, the Board concludes that an appropriate common equity ratio for AltaLink is 35.0%.

If AltaLink were to have a full income tax allowance included in its approved revenue requirement, the Board considers that the appropriate common equity ratio for AltaLink would then be 33.0%.

5.2.4 NGTL

For the same reasons that were provided above, the Board concludes that an appropriate common equity ratio for NGTL, a gas transmission company, is 35.0%.

5.2.5 ATCO Pipelines

The Board notes that no party took the position that ATCO Pipelines has the same or lower business risk as NGTL, the other gas transmission Applicant. From Table 8, the Board notes that Calgary/CAPP considered ATCO Pipelines to be the highest risk investor owned utility, and that CG considered ATCO Pipelines to be tied with AltaGas as the highest risk utility.

Accordingly, in this section, the Board will assess the appropriate equity ratio for ATCO Pipelines and its differences from the typical gas transmission company. In this regard, the Board will draw on its previous analysis and discussion earlier in this section. Further, the Board will address the additional information applicable to ATCO Pipelines.

The Board notes the general consensus that ATCO Pipelines has higher competition risk than NGTL. Several parties suggested that resolution of outstanding gas pipeline competition issues could result in a reduction to the competition risk faced by ATCO Pipelines. The Board notes that at least some of the competition risk faced by ATCO Pipelines may have resulted from the growth of the system to connect customers either already served by NGTL or in direct competition with NGTL for those loads. The Board also notes that ATCO's largest customer is ATCO Gas, which, in the Board's view, has little credit risk. In any event, the Board considers that it should establish capital structures for 2004 based on the business risks that exist at the time of this Proceeding. The Board does not consider that it should speculate on the possible resolution of outstanding pipeline competition issues.

The Board notes that in NGTL's last Phase I proceeding,[122] the Board indicated that there would be a proceeding to address outstanding gas pipeline competition issues (the Competitive Pipeline Module). The Board considers that the Competitive Pipeline Module is the appropriate forum to

[122] Application 1315423, Transcript Volume 1, pages 44-49

deal with the inter-pipeline competition matters that may impact the business risks presently confronting ATCO Pipelines.

The Board directs ATCO Pipelines, at the time of its first GRA following the Board's decision in the Competitive Pipeline Module, to apply either:

a) For a change to its deemed equity ratio, to reflect the change in business risk arising from any directions contained within such a decision; or

b) For maintenance of its then existing capital structure on the basis that no change to business risk resulted from the decision in the Competitive Pipeline Module.

The Board notes that CG recommended that the equity ratio of ATCO Pipelines be set at 40%, which was 8% higher than its recommendation for NGTL, while Calgary/CAPP's recommendation for the equity ratio of ATCO Pipelines at 38% was 5% higher than its recommended equity ratio for NGTL.

The Board notes that if the interveners' differentials were applied to the Board's 35% determination for NGTL, the result would be a range of 40% to 43% for ATCO Pipelines.

The Board agrees with all parties that ATCO Pipelines has higher business risk than NGTL.

The Board notes that the last Board decision for ATCO Pipelines, Decision 2003-100, set the 2003 common equity ratio for both ATCO Pipelines North and ATCO Pipelines South at 43.5%.

Regarding gas transmission companies with higher risk than NGTL, the Board notes Dr. Evan's evidence[123] that Pacific Northern Gas (PNG) had an awarded equity ratio of 42.9% and an adjusted actual equity ratio of 44.2%, with a credit rating of BBB (low). The Board also notes Dr. Booth's view[124] that PNG is a highly risky utility and Dr. Robert's view[125] that PNG is riskier than the other utilities.

The Board also notes that ATCO Pipelines has preferred shares in its capital structure. Although the preferred shares provide additional support to the capital structure, in this analysis, the Board has evaluated the appropriate common equity ratio as if the company had no support from its preferred shares.

Considering all of the above, the Board concludes that an appropriate common equity ratio for ATCO Pipelines is 43.0%.

The Board will further address the issue of ATCO's preferred shares below.

5.3 Electric and Gas Distribution

The Board will now consider the appropriate capital structures for the electric and gas distribution Applicants in light of the 5 topic areas set out in section 5.1 as shown below:

1. The business risk of each utility sector and Applicant;

123 Exhibit 021-24
124 Exhibit 016-11(a), Evidence of L. D. Booth, page 54
125 Transcript, Volume 34, page 5602

2. The Board's last-approved equity ratio for each Applicant (where applicable);
3. Comparable awards by regulators in other jurisdictions;
4. Interest coverage ratio analysis; and
5. Bond rating analysis.

Business Risk

The Board notes the consensus that electric distribution companies are subject to more business risk than electric transmission companies, principally due to their recovery of a significant amount of fixed costs in variable charges and their greater exposure to credit risks.

ATCO proposed that the difference in the equity ratio between its electric distribution companies and its electric TFO should be 12.0-17.0%. The Board observes that 5%-10% of this difference in the equity ratio was due to ATCO's perception of a higher regulatory risk following the passage of the *RDS Amendment Regulation*.[126]

The Board is not persuaded that the *RDS Amendment Regulation* has materially increased the risk to an electric distribution company that has appointed a third-party as RRT provider. The Board notes that the requirement for an electric distribution company to provide a hedged rate is contingent on the default of its RRT provider. The Board notes that it did not receive evidence regarding what contractual protections and security, if any, are available to ATCO in the event of a default by its appointed RRT provider. Also, it is possible that a default would be foreseeable over some period of time prior to it occurring, which may permit time to implement contingency plans to minimize associated impacts. Further, in the event of such a default, an application could be made to the Board to recover, from customers, prudent costs incurred by the electric distribution company in resuming the provision of the RRT. The Board would then consider the merits of such an application, considering factors such as the contractual circumstances and remedies available to the electric distribution company, the circumstances of the RRT appointment, and the potential harm to customers. The Board also notes that no other electric distribution company filed evidence asserting a similar increase in risk.

ATCO also argued that its electric distribution company had higher risk than its electric TFO as a result of potential franchise loss. However, in light of the lack of recent actual occurrences of municipalities closing a transaction pursuant to an option to acquire utilities assets, the Board does not consider, at this time, that the risk of franchise loss or of a municipality acquiring utility assets has increased over what it has been historically. Should there be a material change in the business risk arising from risk of franchise loss an affected utility could apply to the Board at that time to seek appropriate relief.

As shown in Table 8, the Companies, CG and Calgary/CAPP all recommended equity ratios for fully taxable electric distribution companies that were 5% higher than their recommended equity ratios for fully taxable electric transmission companies. The Board understands that this does not necessarily mean that the recommended differential would always be 5%.

ATCO considered the business risk of ATCO Gas to be lower than the business risk of its electric distribution company due to ATCO's perception of a higher regulatory risk for its

[126] Ministerial Order 73/2003, November 4, 2003

electric distribution company. As discussed above, the Board does not agree with ATCO's perception of the magnitude of the regulatory risk for its electric distribution company.

The Board notes that Calgary/CAPP and CG considered that ATCO Gas has the same or slightly higher business risk than a fully taxable electric distribution company, due to higher volatility of revenue resulting from a different rate design and higher sensitivity to fluctuations in weather conditions.

The Board agrees that a gas distribution company has slightly more risk than a taxable electric distribution company due to higher revenue volatility. The Board does not agree with ATCO that the higher revenue volatility of ATCO Gas is more than offset by higher regulatory risk for electric distribution companies.

The Board notes from Table 8 that parties making recommendations, other than ATCO Gas, suggested that the difference between the equity ratio for ATCO Gas and the equity ratio for a fully-taxable electric distribution company should be in the range of 0-2%.

The Board concludes that electric distribution companies have higher business risks than electric transmission companies, and that gas distribution companies have slightly higher business risk than electric distribution companies.

The Board considers that business risk, in isolation, would indicate that gas distribution companies should have a common equity ratio that is 0-2 % higher than the equity ratio for fully taxable electric distribution companies.

Comparison to Previous Board Awards

The Board notes from Table 8 that the most recent equity ratio approved by the Board for a taxable electric distribution company was 35%, and the most recent equity ratio approved by the Board for fully-taxable electric transmission companies was 32%, a difference of 3%. Earlier in this Decision, the Board determined an equity ratio of 33% for taxable electric transmission companies. The Board considers that this factor, in isolation, would indicate an equity ratio of 36% for the taxable electric distribution companies. Since the Board considers that ATCO Gas has slightly higher business risk than the electric distribution companies, the Board considers that this factor, in isolation, this would indicate an equity ratio of more than 36% for ATCO Gas.

The Board notes from Table 8 that the last equity ratio approved for ATCO Gas was 37%, established in Decision 2003-072. The Board considers that the business risks of ATCO Gas have not changed materially from those assessed by the Board in this prior decision, which, in isolation, would indicate an equity ratio for ATCO Gas of 37%.

Comparable Awards by Regulators in Other Jurisdictions

The Board notes its earlier caveats on relying on comparable awards by other regulators in a previous section of this Decision.

The Board notes that the gas distribution companies in Ontario, Enbridge Gas and Union Gas have been awarded a common equity ratio of 35 to 37% and a total equity ratio of 38 to 40%, treating preferred shares as 80% equity.[127]

[127] Exhibit 021-24

The Board considers that this information, in isolation, would indicate that the equity ratio for ATCO Gas could be maintained at its current level of 37%.

The Board does not consider that there are any other electric distribution companies in Canada that are comparable to the electric distribution companies in the restructured electric industry in Alberta.

Interest Coverage Ratio Analysis

The Board notes that Enbridge Gas has been awarded an S&P rating of "2".[128] The Board notes Ms. McShane's estimate that ATCO Gas would warrant an S&P risk profile of between "2" and "3". The Board notes that Ms. McShane estimates an S&P risk ranking of "3" for ATCO Electric. However, the Board earlier noted its view that ATCO had over-stated the business risk level of ATCO Electric. In the Board's view, an appropriate S&P risk score for both distribution utilities is between "2" and "2.5".

The S&P guidelines indicate that for a utility with a risk ranking of "2", a pretax interest coverage ratio in the range of 2.3 to 2.9 times is indicated for an "A" debt rating.

Similarly, the S&P guidelines indicate, through pro-rating the guidelines for a "2" and for a "3", that for a utility with a risk ranking of "2.5", a pretax interest coverage ratio in the range of 2.55 to 3.15 times is indicated for an "A" debt rating.

The Board refers the reader to the Interest Coverage Ratio Analysis section provided earlier in the Electric and Gas Transmission section, including the DBRS guidelines indicated there, as additional factors to consider for determining the appropriate common equity ratio for either an electric or a gas distribution company.

Based on this evidence, the Board concludes that an acceptable pretax interest coverage ratio for a taxable electric distribution company distribution company is at or above 2.2 times.

The Board considers that this factor, in isolation, indicates an equity ratio for taxable electric distribution companies and for gas distribution companies higher than the currently approved 35% for ATCO Electric Distribution.

The Board considers gas distribution companies to have slightly more risk than electric distribution companies and, therefore, the Board considers that this factor, in isolation, indicates that gas distribution companies should have slightly more equity than electric distribution companies.

Bond Rating Analysis

The Board notes that Aquila is the only electric or gas distribution company regulated by the Board with its own bond rating. From Table 10, the Board notes that Aquila has a DBRS rating of A (low) based on an equity ratio of 40 to 45.5%. However, the Board notes that Aquila has a

128 Exhibit 005-11-1, Capital Structures for the ATCO Utilities, Kathleen McShane, page 11

substantial amount of goodwill[129] on its books, amounting to approximately 29% of its assets at the time of the DBRS report, which would require equity support compared to a distribution company without goodwill. Therefore, based on this factor in isolation, the Board concludes that the target equity ratio for a taxable electric distribution company is somewhat below 40%.

The Board considers the most comparable other Canadian gas and electric distribution companies, available in Dr. Evan's evidence, to be Union Gas and Enbridge Gas.

The Board notes that Union Gas Ltd. has an adjusted actual equity ratio of 35% and credit ratings of A and A-.[130] The Board notes that Enbridge Gas has an adjusted actual equity ratio of 51% and credit ratings of A and BBB+.[131] The Board notes that the date of the adjusted actual equity ratio date is not necessarily the same as the dates of the two credit reports. The Board considers this broad range of adjusted actual equity ratios for Ontario gas distribution utilities and its impact on bond ratings to be of little assistance in this Proceeding.

Conclusion

At the beginning of this section, the Board indicated that it would consider a variety of factors for its determination of the appropriate level of equity in the capital structure of electric and gas distribution companies.

As discussed in the preceding sections, in the Board's view, setting an appropriate equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk.

The following table summarizes the indicated equity ratios that arise from various factors as discussed in the earlier sections:

Table 12. Indicated Common Equity Ratios for Distribution Companies by Factor

Factor	Indicated Electric Distribution	Indicated Gas Distribution
Business Risk	Lowest for Distribution	Electric DISCO + 0-2%
Previous Board Awards	~36%	~37%
Awards in Other Jurisdictions	N/A	~37%
Interest Coverage Ratio Analysis	>35%	>35%, >DISCOs
Bond Rating Analysis	<40%	N/A

After considering all of the above factors and after applying its judgment, the Board concludes that an appropriate common equity ratio for a fully taxable electric distribution company with no preferred shares is 37.0%, and that an appropriate common equity ratio for a gas distribution company is 38.0%.

The Board will now consider each electric and gas distribution Applicant, individually.

129 Exhibit 004-12, July 31, 2002 DBRS Report on Aquila, page 5 indicating 54.5% net debt at March 31, 2002 (implies 45.5% equity), and indicating 40.0% deemed equity at December 31, 2001; and Decision 2004-035, page 18

130 Exhibit 021-24

131 Ibid.

5.3.1 FortisAlberta/Aquila

The Board considers that FortisAlberta (formerly Aquila) does not have any material differences in business risk from the typical electric distribution company.

The Board notes that Aquila is a fully taxable electric distribution company with no preferred shares.

Therefore, for the same reasons that were provided above, the Board concludes that an appropriate common equity ratio for FortisAlberta is 37.0%.

5.3.2 ATCO Electric Distribution

The Board considers that ATCO Electric Distribution does not have any material differences in business risk from the typical electric distribution company.

The Board also notes that ATCO Electric Distribution has preferred shares in its capital structure. Although the preferred shares provide additional support to the capital structure, in this analysis, the Board has evaluated the appropriate common equity ratio as if the company had no support from its preferred shares.

The Board concludes that an appropriate common equity ratio for ATCO Electric Distribution is 37.0%.

The Board will further address the issue of ATCO's preferred shares below.

5.3.3 ENMAX Distribution

The Board considers that ENMAX Distribution does not have any material differences in business risk from the typical electric distribution company.

The Board notes ENMAX's argument that it has additional risks due to its municipal ownership, including a fixed dividend requirement, lack of equity access, and the change in regulator, and that as a result it required a capital structure with 50% common equity.

The Board does not agree with ENMAX that its fixed dividend or lack of access to public equity markets raises its risks in the circumstances. In the Board's view, having established a fair return, the Board need not concern itself with the particular internal policies to which a utility may be subject regarding distributions of dividends or acquisition of equity. The Board also considers that the change in regulator for ENMAX does not result in ENMAX having higher risks, all else being equal, than other electric distribution companies regulated by the Board.

With respect to the ENMAX DISCO, which just came under Board jurisdiction in 2004, the capital structure determined in this Proceeding is based on the assumption that the deferral accounts that the Board will ultimately approve for this Applicant will not be materially different than those in existence at the time of this Proceeding for FortisAlberta/Aquila and ATCO Electric Distribution.

For the same reasons that were provided with respect to EPCOR Transmission above, the Board concludes that the equity ratio for a non-taxable electric distribution company should be 2.0% higher than the equity ratio for a fully taxable electric distribution company.

Therefore, the Board concludes that an appropriate common equity ratio for ENMAX Distribution is 39.0%.

5.3.4 EPCOR Distribution

The Board considers that EPCOR Distribution does not have any material differences in business risk from the typical electric distribution company.

With respect to the EPCOR Distribution, which came under Board jurisdiction in 2004, the capital structure determined in this Proceeding is based on the assumption that the deferral accounts that the Board will ultimately approve for this Applicant will not be materially different than those in existence at the time of this Proceeding for FortisAlberta/Aquila and ATCO Electric distribution companies.

For the same reasons that were provided with respect to ENMAX Distribution above, the Board concludes that an appropriate common equity ratio for EPCOR Distribution is 39.0%.

5.3.5 ATCO Gas

The Board considers that ATCO Gas does not have any material differences in business risk from the typical gas distribution company.

The Board notes that ATCO Gas also has preferred shares in its capital structure. Although the preferred shares provide additional support to the capital structure, in this analysis, the Board has evaluated the appropriate common equity ratio as if the company had no support from its preferred shares.

As determined above, the Board concludes that an appropriate common equity ratio for ATCO Gas is 38.0%.

The Board will further address the issue of ATCO's preferred shares below.

5.3.6 AltaGas

The Board considers that AltaGas has greater business risk than the typical gas distribution company.

AltaGas and ATCO Gas considered the business risks of AltaGas to be higher than the business risks of ATCO Gas, due to AltaGas' relatively small size, rural service area, geographically dispersed customers and high level of customer contributions.

Calgary/CAPP was the only party who took the position that AltaGas did not have higher business risks than ATCO Gas. Calgary/CAPP considered the main risk to AltaGas to be commodity cost risk, for which AltaGas has a deferral account. As a result, Calgary/CAPP recommended the same equity ratio for AltaGas as for ATCO Gas.

The Board notes that AltaGas' parent has a credit rating of BBB (low) and has been unable to raise debt with a term longer than five years. AltaGas had the view that, due to its size, it was very unlikely that it would be able to access debt on more favourable terms than its parent.[132]

The Board notes that AltaGas' parent is involved in a significant level of non-regulated activities. The Board is unable to establish the effect that those activities have on the parent's rating. The Board is not persuaded that that AltaGas would not have a higher rating than its parent and that it would not be able to access debt on more favourable terms than its parent. Nonetheless, the Board is persuaded that the business risks of AltaGas are greater than the business risks of a typical gas distribution company because of the nature of its service territory, not necessarily because of its smaller size.

The Board notes that CG's recommended equity ratio for AltaGas was 3% higher than its recommended equity ratio for ATCO Gas, whereas AltaGas and ATCO considered that the equity ratio for AltaGas should be 5% higher. The Board considers that this factor, in isolation indicates that the equity ratio for AltaGas should be 41-43%.

The Board notes that the previous Board approved equity ratio for AltaGas was 41%.

Considering all of the above, the Board concludes that an appropriate common equity ratio for AltaGas is a continuation of its currently approved 41%.

5.4 Utility-Specific Adjustments to ROE

Some parties in this Proceeding indicated that when a common ROE approach is used, it might be necessary to consider a utility-specific adjustment to the common ROE to adequately reflect the investment risks of individual utilities.

In particular, the Board notes that ATCO Pipelines indicated that an adjustment to its ROE was required to adequately compensate its investors for the risks confronting the company, because adjustments to capital structure would not be sufficient.

As noted earlier in this Decision, the Board considers that unique utility-specific adjustments to the generic ROE should only be made in exceptional circumstances where adjusting capital structure alone is not sufficient to reflect the investment risk for a particular Applicant.

The Board notes that the equity ratio approved for ATCO Pipelines in this Decision is marginally lower than the last Board-approved equity ratio for ATCO Pipelines. The Board considers that the capital structure for ATCO Pipelines in this Decision adequately reflects the investment risk for ATCO Pipelines.

The Board concludes that there is no need for utility-specific adjustments to the common ROE for any of the Applicants.

5.5 2004 Deemed Common Equity Ratios

Based on the Board's findings above, the Board approves the following deemed common equity ratios for 2004:

[132] AltaGas Argument, page 32

Table 13. Board Approved Equity Ratios

	Last Board-Approved Common Equity Ratios (%)	2004 Board Approved Common Equity Ratios (%)	Change in Approved Common Equity Ratio (%)
ATCO TFO	32.0	33.0	1.0
AltaLink	34.0[133]	35.0	1.0
EPCOR TFO	35.0	35.0	0.0
NGTL	32.0	35.0	3.0
ATCO Electric DISCO	35.0	37.0	2.0
FortisAlberta (Aquila)	N/A [134]	37.0	N/A
ATCO Gas	37.0	38.0	1.0
ENMAX DISCO	N/A [135]	39.0	N/A
EPCOR DISCO	N/A [125]	39.0	N/A
AltaGas	41.0	41.0	0.0
ATCO Pipelines	43.5	43.0	(0.5)

5.6 ATCO Utilities Preferred Shares

In earlier sections, the Board noted that the 2004 approved common equity ratios in this Decision for the ATCO utilities were not adjusted to reflect any impact of ATCO's use of preferred shares. The Board notes that there was essentially no evidence presented regarding the impact of preferred shares on the required common equity ratios.

The Board has recognized in previous decisions that during the period of time when income tax rebates were in place, it was prudent to utilize preferred share financing in place of debt.

However, the Board considers that there may be merit in further consideration of the appropriateness of the continuing use of preferred shares as a form of financing, to understand the redemption options and to fully explore the related implications and options.

The Board directs ATCO to address the appropriateness of the continuing use of preferred shares as a form of financing, in the next Phase 1 GRA/GTA for ATCO Gas, ATCO Pipelines or ATCO Electric, whichever comes first.

5.7 Process to Adjust Capital Structure

The Board notes that all parties, except for CG, considered that it would be appropriate to address any future changes in capital structure in utility-specific GRA/GTAs. CG proposed a scheduled review of the capital structures of all Applicants.

The Board agrees with the general consensus that it would be more appropriate to address any future changes in capital structure in utility-specific GRA/GTAs. The Board also agrees with the general consensus that such changes should only be pursued if parties perceive that there has

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133 In Decision 2003-061, the Board approved an equity ratio for AltaLink of 32%, plus an additional 2% to offset the impact on the interest coverage ratio of a partial allowance of income taxes in the revenue requirement.

134 The Board did not specifically approve this ratio; it was part of a negotiated settlement approved in Decision 2003-019, which included a deemed 40% equity ratio as one of many settled parameters of the revenue requirement.

135 Both EPCOR and ENMAX Distribution were subject to Board jurisdiction effective January 1, 2004.

been a material change in investment risk since the time of this Proceeding, except as otherwise specifically directed in this Decision.

6 DIRECTIONS TO APPLICANTS

The Board directs any Applicant that has a Board-approved revenue requirement for 2004 that includes a placeholder for ROE and/or capital structure to file with the Board by August 1, 2004, for information, its plans on how it intends to comply with any outstanding directions from the Board to replace the placeholders for ROE and/or capital structure, when these changes might be reflected in customer rates, and the magnitude of the impact on customer rates for the changes arising from this Decision. The Board would appreciate being advised of the status and magnitude of any other known adjustments to rates that might be forthcoming in the same timeframe as the adjustments arising from this Decision.

With respect to applications to establish a 2004 revenue requirement that are currently before the Board for a decision, the Board will use the 2004 generic ROE and capital structure approved in this Decision.

With respect to applications presently before the Board and future applications to establish a revenue requirement for 2005 or later, the Board will apply the generic ROE for that year resulting from the adjustment mechanism approved in this Decision and the capital structure provided for in this Decision, barring the applicant demonstrating a material change has occurred requiring adjustment to capital structure.

7 SUMMARY OF BOARD FINDINGS AND CONCLUSIONS

This section is provided for the convenience of readers. In the event of any difference between the Approvals in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. With respect to the Jurisdictional Question itself, the Board finds that the proper interpretation of section 37 of the GUA would allow the Board to determine the capital structure for the relevant test period (2004 or 2005) for each gas utility under its jurisdiction by way of a generic proceeding and to establish a standardized approach based on a formula for determining the return on common equity for gas utilities. 7

2. Accordingly, the Board finds that the evidence in the Proceeding indicates that implementation of a generic approach is in the public interest and accordingly, the Board will implement a generic approach to ROE and capital structure. In the following sections, the Board will address the issues associated with the determinations necessary to appropriately implement this approach. 11

3. The Board will therefore establish a common, or generic, ROE to be applied to all Applicants. The Board will address the need for any utility-specific adjustments to the common ROE in the capital structure section of this Decision. 14

4. Based on the above-determined risk-free rate of 5.68%, MRP of 5.50%, beta of 0.55, and allowance for flotation costs of 0.50%, the Board concludes that a reasonable CAPM estimate for 2004 is 9.20%.. 21

5. On balance, the Board concludes that the results of the ERP tests other than CAPM would generally support a 2004 ROE above the Board's CAPM estimate, but that for the reasons set out above only limited weight should be placed on the results of the ERP tests other than CAPM. 23

6. As a result of the above noted concerns, the Board concludes that no weight should be placed on the results of the DCF tests presented in this Proceeding. 23

7. The Board concludes that it should place no weight on the CE test because of the implementation problems of the CE test and the above-noted conceptual and methodological concerns with the CE test. 24

8. Directionally, the evidence on recent awards for other Canadian utilities would support a 2004 ROE above the Board's CAPM estimate. However, the Board concludes that limited weight should be placed on this evidence due to the potential for circularity. 25

9. Directionally, the evidence on the awards available to U.S. utilities would support a 2004 ROE above the Board's CAPM estimate. However, the Board concludes that limited weight should be placed on this evidence due to the differences in the regulatory, fiscal, monetary, and tax regimes in the two countries... 26

10. Although, directionally, the absolute level of return for Alliance and M&NP would support a 2004 ROE above the Board's CAPM estimate, the Board concludes, based on the above analysis, that it should place limited weight on the Alliance and M&NP returns. 27

11. Directionally, the Board concludes that the experience regarding the market-to-book ratios of utilities and the experience regarding the acquisition of Alberta utilities in recent years is relevant and supports continuation of an ROE at or below the Board's CAPM estimate. 28

12. Directionally, the Board considers that the experience with Income Trusts would support an ROE at or below the Board's CAPM estimate. However, for the reasons cited above, the Board concludes that limited weight should be placed on this experience............................ 29

13. On balance, the Board concludes that the evidence on forecast pension returns would support a modest increase from the Board's CAPM estimate. 29

14. The Board concludes that there is no basis on which to place any weight, other than already reflected in earlier tests, on other specific investment opportunities potentially available to utility investors or on stated expectations of return from such opportunities. 30

15. In consideration of the impact of the above factors, it is the judgment of the Board that it would be appropriate to establish the 2004 ROE at a level that is 40 basis points above the Board's CAPM estimate. Therefore, the Board concludes the generic ROE for 2004 should be set at 9.60%. 31

8 SUMMARY OF BOARD DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

9 ORDER

For and subject to the reasons set out in this Decision, IT IS HEREBY ORDERED THAT:

1. With respect to Applicants that have a Board-approved revenue requirement for 2004 that includes a placeholder for ROE and/or capital structure, the placeholder for ROE shall be replaced by 9.60% and the placeholder for capital structure shall be replaced as set out in this Decision;

2. With respect to applications by an Applicant to establish a 2004 revenue requirement that are currently before the Board, the Board shall apply an ROE of 9.60% and shall apply the capital structure as set out in this Decision; and

3. With respect to current or future applications by an Applicant to establish a revenue requirement for 2005 or later years, the Board shall apply the common ROE for that year resulting from the adjustment mechanism approved in this Decision and shall apply the capital structure as set out in this Decision for such Applicant, unless the Applicant can demonstrate to the satisfaction of the Board that there has been a material change in business risk that warrants a change to the capital structure set out in this Decision.

Dated in Calgary Alberta on July 2, 2004.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

A. J. Berg, P. Eng
Presiding Member

(original signed by)

R. G. Lock, P. Eng
Member

(original signed by)

J. I. Douglas, FCA
Member

APPENDIX 1 – HEARING PARTICIPANTS

Name of Organization (Abbreviation) Counsel or Representative (APPLICANTS)	Witnesses
AltaGas Utilities Inc. (AltaGas) F. Martin R. Jeerakathil	L. Heikkinen K. McShane
AltaLink Management Ltd. (AltaLink) H. Williamson	Dr. R. Evans K. Johnston D. Frehlich J. Harbilas
Aquila Networks Canada (Alberta) Ltd. (Aquila) T. Dalgleish	Dr. R. Evans
ATCO Utilities (ATCO) L. Smith	K. McShane J. McNeil D. Belsheim O. Edmondson
ENMAX Power Corporation (ENMAX) L. Cusano D. Wood	R. Henderson A. Buchignani R. Falconer Dr. J. Neri
EPCOR Utilities Inc. (EPCOR) D. Crowther	Dr. R. Evans
NOVA Gas Transmission Ltd. (NGTL) K. Yates Ms. Moreland D. Holgate	R. Girling S. Brett G. Lackenbauer P. Murphy Dr. P. Carpenter M. Feldman S. Pohlod Dr. W. Langford A. Jamal G. Zwick Dr. L. Kolbe Dr. M. Vilbert

Name of Organization (Abbreviation) Counsel or Representative (INTERVENERS)	Witnesses
Alberta Association of Municipal Districts and Counties, Federation of Alberta Gas Co-ops Ltd., Gas Alberta Inc. and Municipal and Gas Co-op Intervenors (AAMDC) T. Marriott	
Alberta Federation of REAs (REAs) K. Sisson	
Alberta Irrigation Projects Association (AIPA) H. Unryn	
BP Canada Energy Company (BP) D. McGrath	
Canadian Association of Petroleum Producers (CAPP) N. Schultz	Dr. L. Booth M. Romanow G. Stringham P. Tahmazian D. Gilbert M. Pinney T. Kelley P. Nettleton
Canadian Gas Association (CGA) P. Jeffrey	M. Cleland P. Case
Cargill Power & Gas Markets (Cargill) M. Stauft	
Cities of Lethbridge and Red Deer (Cities) P. Smith	
City of Calgary (Calgary) P. Quinton-Campbell R. Brander	K. Sharp H. Johnson J. McCormick Dr. L. Booth
Consumers Coalition of Alberta (CCA) J. Wachowich	
Consumers Group/AUMA (Consumers Group) J. Bryan	W. Marcus R. Liddle Dr. L. Kryzanowski Dr. G. Roberts
First Nations Communities (First Nations) J. Graves A. Ackroyd	
Fortis Alberta Holdings Inc. (Fortis) B. Ho	

Name of Organization (Abbreviation) **Counsel or Representative (INTERVENERS)**	**Witnesses**
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster D. Macnamara	
Independent Power Producers Society of Alberta/Senior Petroleum Producers Association (IPPSA/SPPA) L. Manning	D. Hildebrand A. Moon J. Keating
Nexen Inc. (Nexen) S. Young	
Public Institutional Consumers of Alberta (PICA) N. McKenzie	
Utilities Consumers Advocate (UCA) R. McCreary R. Jackson	

BOARD STAFF B. McNulty (Board Counsel) J. Wilson S. Allen W. Taylor R. Litt R. Schroeder Dr. V. Mehrotra	

APPENDIX 2 – ABBREVIATIONS

AESO	Alberta Electric System Operator
ANG	Alberta Natural Gas Ltd.
ATWACC	After Tax Weighted Average Cost of Capital
CAPM	Capital Assets Pricing Model
CE Test	Comparable Earnings Test
DCF Test	Discounted Cash Flow Test
DISCO	Electric or Gas Distribution Utility
ECAPM	Empirical Capital Assets Pricing Model
Equity Ratio	Common Equity as a Percentage of Total Financing
ERP Test	Equity Risk Premium Test
Foothills	Foothills Pipelines Inc.
GRA/GTA	General Rate Application/General Tariff Application
MRP	Market Risk Premium
NEB	National Energy Board
ROE	Rate of Return on Common Equity
RTO	Regional Transmission Organization
S&P	Standard & Poor's
TFO	Electric Transmission Facility Owner
TQM	Trans Quebec and Maritimes Pipeline

APPENDIX 3 – BOARD LETTER OF SEPTEMBER 30, 2002

"2002-09-30 EUB Letter.doc"

(Consists of 8 pages)

Also, within this embedded document there are two further embedded documents.
(Appendix B consists of 5 pages and Appendix C consists of 1 page)

EUB Alberta Energy and Utilities Board
Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

File No. 5681-1

September 30, 2002

Sent to Parties on Various Utility Branch Lists via Email

Dear Sir/Madam:

PROCEEDING NO. 1271597
GENERIC COST OF CAPITAL HEARING - ELECTRIC AND GAS UTILITIES

- **Notice of Registration as Intervenors**
- **Notice of Pre-hearing Meeting – November 26, 2002**

On May 6, 2002, the Board received a request from the City of Calgary (Calgary) that the Board institute a proceeding to consider generic cost of capital matters for electric and gas utilities under the Board's jurisdiction. The Board responded to Calgary by letter dated June 6, 2002. Copies of both letters are attached as Appendix B and Appendix C[1], respectively.

The Board has decided to call a generic hearing pursuant to its powers to hold an inquiry under Section 46 of the *Public Utilities Board Act* (PUB Act) to consider cost of capital matters for electric, gas and pipeline utilities under its jurisdiction. This would include pipeline and electric transmission companies as well as electric and gas distribution companies.

The Board will hold a pre-hearing meeting as specified below to deal with the following issues:

- Determination of the scope of the proceeding and list of issues
- Determination of procedural matters that might be adopted for such a hearing.

A preliminary list of issues and procedural matters that the Board will consider through such a process is attached to this letter as Appendix A.

The Board requests that interested parties consider this preliminary list of issues and procedural matters and provide the Board with their detailed written submissions on the appropriateness of each issue or matter as well as their submissions with respect to additional issues or matters that might appropriately be considered through such a generic proceeding.

[1] Please note that these Appendices are embedded and may take a second or two to appear.

The following are key dates that the Board has established as follows:

Registration as intervenors with the Board	October 18, 2002
Written Submissions: List of Issues and Procedural Matters	November 12, 2002
Pre-Hearing Meeting	November 26, 2002
Hearing (Preliminary Schedule)	2^{nd} Quarter 2003

After receiving parties' written submissions the Board will prepare a consolidated list of issues and procedural matters for discussion at the pre-hearing meeting.

The pre-hearing meeting will be held as follows:

- DATE: November 26, 2002
- TIME: 9:00 a.m.
- PLACE: Govier Hall, EUB Calgary offices (2^{nd} floor, 640 – 5 Avenue SW)

The generic hearing would likely be scheduled for the 2^{nd} quarter of 2003.

The Board is prepared to consider submissions respecting cost recovery for this proceeding given possible future cost savings associated with streamlining of the Cost of Capital determination process. The Board has the ability to allow costs of the proceeding and to direct that such costs be borne by consumers through the utilities' hearing cost reserve accounts pursuant to the Board's discretion under Section 68 of the PUB Act and pursuant to Rules 55 and 57 of the Board's Rules of Practice.

The Board would appreciate the efforts of any or all parties to work together, in advance of the pre-hearing meeting, in order to consolidate and simplify the views of parties on any matter, including procedural and timing issues.

Any questions or correspondence, including submissions, should be directed to the writer in the EUB's Calgary office. I can be reached at (403) 297-3539 telephone, (403) 297-6104 fax, or via email at jim.wilson@gov.ab.ca. Parties should also file an electronic copy of their registrations and any submissions at the email address eub.utl@gov.ab.ca.

Yours truly,

(Original signed " J. Wilson")

Jim Wilson
Lead Application Officer

Attachments

APPENDIX A

Preliminary List of Issues and Procedural Matters

A preliminary list of issues and procedural matters that will be considered at a pre-hearing meeting for a EUB generic hearing into utility cost of capital matters.

For clarity, the Board will not be discussing the merits of each issue in the list below (i.e. in section **I. Preliminary List of Issues)** but the Board, in its Decision arising from the pre-hearing meeting, will determine the scope of the proceeding.

Further, the Board will make determinations, in its Decision arising from the pre-hearing meeting, on procedural items listed below (i.e. in section **II. Preliminary List of Procedural Matters**)

I. Preliminary List of Issues

A. Pros and Cons of a Standardized Approach

1) In general and without specifying which methodology (ies) might be used, what are the pros and cons of adopting a standard methodology (ies) for setting equity rate of return in utility rate cases?

2) In general and without specifying which methodology (ies) might be used, what are the pros and cons of adopting a standard methodology (ies) for setting capital structure in utility rate cases?

3) Is the adoption of a generic approach to utility equity rate of return and capital structure in keeping with developments in other jurisdictions in North America?

B. Alternatives within a Standardized Approach

1) Assuming that the establishment of a standardized approach to setting equity rate of return is desirable:

    i. What options or alternatives should the Board consider? For example, the comparative earnings method, the risk premium method, the discounted cash flow method, ATWACC, and the NEB's approach that includes an adjustment formula.

    ii. What are the pros and cons of each option or combination of options?

2) Assuming that the establishment of a standardized approach to setting utility capital structures is desirable:

   i. What options should the Board consider?

   ii. What are the pros and cons of each option or combination of options?

C. Standardized vs. One-by-One Approach?

1) Would it be correct to consider a standardized approach to setting utility equity rate of return for all types of utilities under the Board's jurisdiction, including gas transmission, gas distribution, gas retail, electric transmission, electric distribution and electric regulated rate option providers?

2) Would it be correct to consider a single standardized approach to setting utility capital structure for all types of utilities under the Board's jurisdiction, again including gas transmission, gas distribution, gas retail, electric transmission, electric distribution and electric regulated rate option providers?

3) What principles should guide the determination of capital structure for utilities that are owned by holding companies, i.e. what principles and issues should be taken into account in dealing with a deemed vs. actual capital structure?

4) What differences exist between investor owned and municipally owned utilities that affect determination of cost of capital issues and how should those differences be taken into account with respect to cost of capital issues including return on equity, capital structure, debt costs and income tax?

D. Timing Issues

1) The Board is considering setting an implementation date for any cost of capital methodology (ies) adopted sufficiently far in advance, so as not to impact rate cases or settlement negotiations occurring during the generic hearing process. Alternately, the Board could direct parties to use placeholders for rate of return and capital structure with respect to applications not presently before the Board. What are the pros and cons of each approach?

2) What are the implications of the substance and timing of a cost of capital generic hearing with respect to the possible regulation by the Board of municipally owned utilities?

3) Should the Board consider setting an expiry date or a mandatory review date for any methodology (ies) it may determine to be appropriate for cost of capital issues? If so, what is an appropriate length of time that should elapse before a review is required?

4) How should adjustments in equity rate of return and capital structure be dealt with between test periods?

E. Special Considerations

1) Should parties have the option of agreeing, through a negotiated settlement process, on an equity rate of return and/or capital structure that is different from the equity rate of return and/or capital structure that would result using the standardized approach?

2) What provision, if any, would an inquiry into cost of capital issues need to make with respect to the Performance Based Rates (PBR) methodology or other evolving methodologies for setting rates or rate components?

3) Should the Board consider negotiated pricing arrangements in respect of expansion or merchant projects as a substitute for traditional forms of earning through equity rate of return and capital structure, (for example the Alliance Pipeline)?

II. Preliminary List of Procedural Matters

A. One or Two Phases

1) At a generic hearing:

   i. Should the Board conduct a single-phase hearing to consider both equity rate of return and capital structure generic issues?

   ii. Alternately, should there be two separate phases, one into equity rate of return applicable to all types of utilities and the other into capital structure for each type of utility?

   iii. Should the proceeding be with respect to all utilities or do the distinctions between gas, pipeline and electric industries merit separate and distinct generic hearings or phases?

B. Schedule for the Proceeding

1) Designation of "Applicant(s)" for initial evidence submission

2) Desired Process and dates for the following:

    i. Initial Evidence
    ii. IRs
    iii. Response to IRs
    iv. Intervenor Evidence
    v. IRs to Intervenors
    vi. Response to IRs to Intervenors
    vii. Rebuttal Evidence

C. Costs

1) With respect to costs for the generic hearing(s):

    i. Should some parties be only partially funded?

    ii. If so, which parties should this apply to?

    iii. How could parties be provided with incentives to combine positions where possible to achieve cost and time efficiencies?

APPENDIX B

City of Calgary Letter dated May 6, 2002

"Appendix B.doc"

(Consists of 5 pages)

Please note that the above Appendix is embedded and may take a second or two to appear.

APPENDIX C

Board Letter dated June 6, 2002

"Appendix C.doc"

(Consists of 1 page)

Please note that the above Appendix is embedded and may take a second or two to appear.

Burnet,
Duckworth
& Palmer LLP
Law Firm

Reply to: R. Bruce Brander
Direct Phone: **(403) 260-0165**
Direct Fax: **(403) 260-0332**
rbb@bdplaw.com

Assistant: Donna Koenig
Direct Phone: **(403) 260-0186**
Our File: 50343-135

VIA EMAIL

May 6, 2002

Alberta Energy and Utilities Board
640 - 5th Ave. S.W.
Calgary, AB T2P 3G4

Attention: R. D. Heggie
Executive Manager, Utilities Branch

Dear Sirs:

Re: Cost of Capital for Electric and Gas Utilities under the Board's Jurisdiction

Pursuant to the provisions of the *Public Utilities Board Act*, R.S.A. 2000 c. P-45 (the "PUB Act"), the *Gas Utilities Act*, R.S.A. 2000, c. G-5, (the "GUA"), the *Electric Utilities Ac*t, R.S.A. 2000 (the "EUA"), c. E-5, and the A*lberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17 (the "AEUB Act"), The City of Calgary ("Calgary") hereby applies to the Board to convene a proceeding or inquiry to establish a mechanism for the appropriate cost of capital (return on equity and capital structure] for the gas and electric utilities under the Board's jurisdiction. This Application is being made on behalf of Calgary by its legal counsel Burnet Duckworth & Palmer LLP. The particulars of, and support for, this Application, are provided in the following sections.

Interest of Calgary

As the Board is aware, Calgary has a long history of intervention in regulatory proceedings which impact its citizens. With respect to gas utilities, core customers within Calgary represent approximately 70% of the gas consumption and revenue requirement of ATCO Gas South. Through the ATCO Gas South and ATCO Pipelines South rate structure, core customers within Calgary are also responsible for approximately 40% of the revenue requirement of ATCO Pipelines South. Consumers within Calgary also consume approximately one-sixth of the provincial electrical production, and are affected by the rates charged by the Transmission Facility Owners ("TFO"'s).

Cost of capital (including return on equity, capital structure, and associated income taxes) is a significant portion of the revenue requirement of any regulated utility. Using the applied for amounts for 2001 for ATCO Gas South, return on equity and taxes were about 16% of the revenue requirement, and for ATCO Pipelines South about 33%. Based on the TFO materials filed for 2001, return on equity and associated taxes for ATCO Electric and TransAlta were approximately 35% and 33% respectively (EPCOR Transmission Inc. with no tax was approximately 16%).[1]

[1] The percentages increase significantly if return on rate base is used instead of return on equity.

BD&P

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www.bdplaw.com

Frank L. Burnet Q.C. (1890-1982)
Thomas J. Duckworth Q.C., Counsel

In recent years Calgary has retained experts to present evidence on cost of capital in several proceedings: Canadian Western Natural Gas 1997/1998 GRA, the 2001 TFO Tarff Applications of ATCO Electric, TransAlta and EPCOR Transmission Inc., the ATCO Gas South 2001/2002 GRA, and the ATCO Pipelines South 2001/2002 GRA. As one of the few parties that can afford to carry the significant cost of presenting evidence in this area, Calgary expects that it will be presenting cost of capital evidence in future proceedings affecting its citizens.

As a result, the citizens represented by Calgary are directly affected by return on equity and capital structure issues

Grounds

As noted above, cost of capital constitutes a significant portion of the revenue requirement of the utilities regulated by the Board. Dealing with cost of capital issues is also a significant portion of hearing costs. Cost of capital is also an area where there are a limited number of experts available and the costs of presenting such expert reports is a substantial cost to an intervention – often at rates that exceed the Board's guidelines.

In the recent ATCO Gas South and ATCO Pipelines South proceedings the return on equity and capital structure experts retained by ATCO and Calgary cost just under $200,000 for each proceeding. In the TFO proceedings for 2001 rates, where the three TFO’s each filed separate return on equity evidence, expert witness costs totaled about $711,000 for Calgary, ATCO Electric and TransAlta[2]. In addition to the fees of the cost of capital experts, there are significant additional costs for legal counsel, and other experts, to interact with the cost of capital experts to present the case. Where an intervenor incurs these costs as part of the hearing process, the intervenor not only must carry the cost until a Costs Order is issued, but also bears the risks that the utility will oppose the costs which the intervenor has incurred to benefit all customers, or that hourly rates that are in excess of the Board's guidelines will be denied. In addition, the intervenors also bear the utility's costs through the revenue requirement and the hearing reserve account.

In the ATCO Gas South and ATCO Pipelines South 2001/2002 GRA’s the utilities filed identical return on equity evidence. Calgary, as the intervenor dealing with return on equity, then had to file evidence responding to the utilities’ return on equity requests in two different proceedings, with two attendances by the experts. In Decisions 2000-96 and 2000-97 dealing with these GRA’s, the Board issued identical reasons on return on equity matters[3] and made, *inter alia*, the following observations:

> The Board is concerned that, despite its volume, the nature of the expert evidence provided is ultimately of little probative value to the Board in establishing this important determinant of the utility’s revenue requirement.
>
> In particular the Board notes the effect that the application of professional judgement [sic] has on the outcome of the equity risk premium test. This test has been noted to be the mainstay of this Board and other Canadian regulatory boards over recent periods…
> ….

[2] Calgary, $163,000 (for evidence on all three TFO's); ATCO Electric TFO, $79,000; TransAlta, $468,000. Calgary has not yet been provided details of EPCOR Transmission Inc.'s costs.
[3] Decision 2000-96 pages 52 – 59; Decision 2000-97 pages 31 - 38.

> Further, these [equity risk premium] estimates are far enough apart that the underlying evidence is of little value to the Board in establishing an accurate and well justified estimate of the utility rate of return required to maintain the financial integrity of the utility in the eyes of investors and the market. Subsequently, the Board must rely on an examination of past awards to CWNG to determine if there is a requirement for adjustments to those awards. The Board is also of the view that alternative methods of determining appropriate utility return may need to be examined for use in future rate cases. (emphasis added)

Other Canadian regulatory boards have addressed concerns with respect to the determination of the appropriate cost of capital by taking what could be called a "generic" or formulaic approach to the issue. These include:

- National Energy Board, Multi-Pipeline Cost of Capital, RH-2-94[4],
- British Columbia Utilities Commission, Return on Common Equity Decision, June 10, 1994, Order G-35-94
- Ontario Energy Board Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities, March 1997,
- Manitoba Public Utilities Board Order 49095, page 50.

In Alberta, there has been some limited discussion of a generic approach to return on equity:

- In the Board's Costs Workshop of June 20, 2000 the question of why intervenors did not reduce costs through a different approach to return on equity was raised. Intervenors responded that they had to deal with the applications as filed by the utilities, and no utility had filed for a formula based approach to return on equity.

- In the 2001 TFO proceeding the evidence of Drs. Booth and Berkowitz on behalf of Calgary recommended the use of an adjustment formula for 2002 return on equity[5]. The issue of a formula based approach to return on equity was briefly discussed during the TransAlta portion of the hearing.[6]

- In the 2001/2002 ATCO Gas South and ATCO Pipelines South GRA's the evidence of Drs. Booth and Berkowitz on behalf of Calgary again suggested consideration of an adjustment formula for 2002.[7]

To date, so far as Calgary is aware, none of the utilities under the Board's jurisdiction has filed an application to have cost of capital determined on a generic or formulaic basis, nor is Calgary aware that any of the utilities are planning on doing so. However, Calgary believes that there will be several proceedings in the near future where cost of capital will have to be addressed. These include:

- ATCO Gas 2003 – 2000x GRA for ATCO Gas North and South combined,

[4] In proceeding RH-4-2001 TransCanada PipeLines Limited sought a review of the RH-2-94 Decision and presented a methodology that the EUB was presented with by TransAlta in the 1999/2000 GTA, and was included in TransAlta's 2001 TFO filing.
[5] Applications 2000132, 2000133 and 2000134, Evidence of Laurence D. Booth and Michael K. Berkowitz, page 75.
[6] 2001/2002 TFO Proceeding, September 25, 2000, Volume 3, pages 497 – 501.
[7] AGS GRA Exhibit 43, Evidence of Laurence D. Booth and Michael K. Berkowitz, page 68; APS GRA Exhibit 69, Evidence of Laurence D. Booth and Michael K. Berkowitz, page 63.

- A combined ATCO Pipelines North and South 2003 – 2000x GRA,

- The ATCO Electric TFO (and DISCO) negotiated settlement expires in 2002, and ATCO Electric has notified the Board that a 2003 – 2005 combined application for Transmission and Distribution will be filed in mid to late second quarter 2002.

- The EPCOR Transmission Inc. TFO negotiated settlement will expire at the end of 2002 and, presumably, a 2003 GRA will result,

- Altalink Management Ltd. TFO will need to file a GRA for 2002 and subsequent years.

In addition to the foregoing there may be other gas and electric utilities, with which Calgary is not involved, that will require rate hearings for 2003 and beyond.

Given the recent history with cost of capital matters, and the likelihood of several hearings in the near future dealing with cost of capital, it is Calgary's view that there would be several advantages to a "generic" cost of capital proceeding:

- *Reduction in expert witness costs.* Even if all of the utilities used different experts for a generic proceeding, there would be a likely cost saving to intervenors in only having to retain cost of capital experts for a single proceeding, instead of for multiple proceedings.

- *Reduction in overall hearing costs.* The fees for cost of capital experts are only a portion of the overall expense of dealing with cost of capital in a hearing. Fees for counsel and other experts to deal with cost of capital matters and present the case are also significant. Calgary would expect that a generic proceeding would result in cost reductions through synergies or economies of scale.

- *Efficiencies in use of Board resources.* Dealing with cost of capital matters for several utilities at the same time would, presumably, allow the Board to deal with the issues more expeditiously as it would not have to be dealing with evidence filed at different times, and in different proceedings, when ensuring that the issues are addressed in a consistent manner.

- *Future Cost Savings.* Should a generic proceeding result in Board decisions on cost of capital that last over a period of years, then Calgary would expect that future cost savings would be achieved either through simplification of future GRA's, or through facilitation of negotiated settlements by removing the cost of capital issue from negotiations.

Statutory Provisions

Calgary believes that the Board has the required jurisdiction to convene a generic cost of capital proceeding pursuant to the provisions of the AEUB Act (ss. 13 and 15); the PUB Act (ss. 36, 37, 46, 47, 89 and 90); the GUA (ss. 22, 36, and 37); and the EUA (ss. 47, 49, and 52).

Consultation Process

As discussed above, Calgary does not believe that the utilities under the Board's jurisdiction have shown any interest in the past in a generic approach to cost of capital issues. As a result, and considering the number of utilities potentially involved, Calgary concluded that the best way to address this issue was through an application to the Board that would allow all interested parties to express their views. Calgary has, however, held informal discussions with some intervenor groups and believes that customer groups, who ultimately bear the burden of cost of capital litigation, will be supportive of any approach that has the potential to reduce costs.

Summary of Relief Requested

Calgary requests that the Board institute a proceeding to determine:

1. the appropriate rate of return on common equity for each utility examined,

2. the appropriate capital structure for each utility examined,

3. the time frame over which the rate of return on common equity should apply,

4. if the time frame for the rate of return on common equity is to be more and one year, or other specified test period, the mechanism by which the rate of return would be adjusted in further years,

5. the time frame over which capital structure should apply, and the process for adjusting capital structure,

6. the appropriate regulatory process for future proceedings dealing with return on equity and capital structure.

Communications

All communications with respect to this Application can be addressed to the undersigned.

Service

Calgary will be providing a copy of this Application to the Interested Party lists from the ATCO Gas South and ATCO Pipelines South GRA's, GCRR Methodology Proceeding, the 2001/2002 TFO Proceeding, and the TransAlta/Altalink Proceeding. Copies will be provided to any other party, or list, that the Board directs.

Yours truly,

Burnet, Duckworth & Palmer LLP

(Original signed by R. Bruce Brander)

R. Bruce Brander

RBB\dk
cc: Interested Parties Lists:
ATCO Gas South 2001/2002 GRA
ATCO Pipelines South 2001/2002 GRA
GCRR Methodology Proceeding
2001/2002 TFO Proceeding
TransAlta/Altalink Proeeding
G:\050343\0135\AEUB Capital Cost Application from Calgary May 6 2002.doc

EUB Alberta Energy and Utilities Board
Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

Via Email and Mail

File No.: 5681-1

June 6, 2002

Mr. R. Bruce Brander
Burnet, Duckworth & Palmer LLP
Law Firm
1400, 350 - 7 AVE SW
CALGARY AB T2P 3N9

Dear Mr. Brander:

APPLICATION 1271597
COST OF CAPITAL FOR ELECTRIC AND GAS UTILITIES UNDER THE BOARD'S JURISDICTION

I refer to your letter of May 6, 2002, on behalf of the City of Calgary, requesting that the Board convene a proceeding or inquiry to establish a mechanism for determining the cost of capital for utilities under the Board's jurisdiction.

The Board has now had the opportunity to thoroughly review this request. Upon reflection, the Board considers that it would be appropriate to await the National Energy Board's upcoming decision on rate of return before proceeding to deal with this issue.

We will be contacting interested parties further with respect to procedure once this decision has been released.

Yours truly,

<original signed by>

Robert D. Heggie
Executive Manager
Utilities Branch

pc: Interested Parties Lists via Email Only:
ATCO Gas South 2001/2002 GRA
ATCO Pipelines South 2001/2002 GRA
GCRR Methodology Proceeding
2001/2002 TFO Proceeding
TransAlta/AltaLink Proceeding
EAL Congestion Management Proceeding

Board Initiated Proceeding, 2005 Generic ROE Formula Result
EUB Order U2004-423

Other Utilities
Order U2004-423

MADE at the City of Calgary, in the Province of Alberta, on 30th day of November 2004.	ALBERTA ENERGY AND UTILITIES BOARD

Board Initiated Proceeding 2005 Return on Equity	Proceeding No. 1371189

1 BACKGROUND AND DETAILS

The Alberta Energy and Utilities Board (Board) released Decision 2004-052 on July 2, 2004 regarding the Generic Cost of Capital proceeding. This Decision set a generic rate of return on common equity (Return on Equity or ROE) of 9.60% for 2004.[1] This Decision also approved an annual adjustment mechanism or formula for the purpose of establishing the generic ROE for 2005 and later years.

The adjustment formula set out in Decision 2004-052, at page 32, is as follows:

> $ROE_t = 9.60\% + [0.75 \times (YLD_t - 5.68\%)]$
>
> where YLD_t = the forecast long-term Canada bond yield for year t.
>
> Consistent with the approach used by the NEB, the forecast long-term Canada bond yield for year t shall be calculated as the average of the 3-month-out and 12-month-out forecasts of 10-year Canada yields as reported in the Consensus Forecasts[2] issue in November of the previous year, plus the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October in the previous year, as reported in the National Post.

The 3-month-out and 12-month-out forecasts of 10-year Government of Canada (Canada) yields as reported in the November 2004 Consensus Forecasts issue were 4.90% and 5.20% respectively, resulting in an average forecast 10-year Canada bond yield of 5.05% for 2005. To this forecast, the EUB added 0.50% or 50 basis points, representing the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October 2004, as reported in the National Post. This calculation resulted in a forecasted 2005 long-term Canada bond yield (YLD_{2005}) of 5.55%, which is 0.13%, or 13 basis points, lower than the Board approved forecast long-term Canada bond yield of 5.68% for 2004. Multiplying this 13 basis point yield differential by 75% produced a downward adjustment of 0.10% or 10 basis points.

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1 Page 31
2 Published by Consensus Economics Inc., London, England

Applying this downward adjustment of 10 basis points to the 2004 ROE of 9.60% results in a generic ROE of 9.50% for 2005.

The 2005 generic ROE is applicable to any adjudicated determination of a 2005 revenue requirement, for each of the Applicants listed in Decision 2004-052, as presented below. The Board may also apply the 2005 generic ROE to any other utility that is currently or that comes under its jurisdiction. For greater certainty, the Board notes that the 2005 generic ROE would not apply to any utility that continues to operate under its final 2004 rates and for which there is no proceeding to establish revised final rates for 2005.

The Applicant utilities for Decision 2004-052 were:

AltaGas Utilities Inc.
AltaLink Management Ltd. (AltaLink, L.P.)
ATCO Electric Ltd. (Distribution)
ATCO Electric Ltd. (Transmission)
ATCO Gas
ATCO Pipelines
ENMAX Power Corporation (Distribution)
EPCOR Distribution Inc.
EPCOR Transmission Inc.
FortisAlberta
NOVA Gas Transmission Ltd.

2 ORDER

The Board hereby approves, in accordance with Decision 2004-052, a 2005 generic Return on Equity of 9.50%.

END OF DOCUMENT

Board Initiated Proceeding, 2006 Generic ROE Formula Result
EUB Order - U2005-410

MADE at the City of Calgary, in the Province of Alberta, on 22nd day of November 2005.	ALBERTA ENERGY AND UTILITIES BOARD

Board Initiated Proceeding 2006 Generic Return on Equity Formula Result	Application No. 1428134

1 BACKGROUND AND DETAILS

The Alberta Energy and Utilities Board (Board) released Decision 2004-052 on July 2, 2004 regarding the Generic Cost of Capital proceeding. Decision 2004-052 set a generic rate of return on common equity (Return on Equity or ROE) of 9.60% for 2004.[1] Decision 2004-052 also approved an annual adjustment mechanism or formula for the purpose of establishing the generic ROE for 2005 and later years.

The adjustment formula set out in Decision 2004-052, at page 32, is as follows:

> $ROE_t = 9.60\% + [0.75 \text{ x } (YLD_t – 5.68\%)]$
>
> where YLD_t = the forecast long-term Canada bond yield for year t.
>
> Consistent with the approach used by the NEB, the forecast long-term Canada bond yield for year t shall be calculated as the average of the 3-month-out and 12-month-out forecasts of 10-year Canada yields as reported in the Consensus Forecasts[2] issue in November of the previous year, plus the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October in the previous year, as reported in the National Post.

The 3-month-out and 12-month-out forecasts of 10-year Government of Canada (Canada) yields as reported in the November 2005 Consensus Forecasts issue were 4.4% and 4.7% respectively, resulting in an average forecast 10-year Canada bond yield of 4.55% for 2006. To this forecast, the EUB added 0.23% or 23 basis points, representing the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October 2005, as reported in the National Post. This calculation resulted in a forecasted 2006 long-term Canada bond yield (YLD_{2006}) of 4.78%, which is 0.90%, or 90 basis points, lower than the Board approved forecast long-term Canada bond yield of 5.68% for 2004. Multiplying this 90 basis point yield differential by 75% produced a downward adjustment of 0.68% or 68 basis points

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1 Page 31
2 Published by Consensus Economics Inc., London, England

(rounded to two decimal places). Applying this downward adjustment of 68 basis points to the 2004 ROE of 9.60% results in a generic ROE of 8.93% for 2006. This is 0.57% or 57 basis points lower than the 2005 generic ROE of 9.50%

The 2006 generic ROE is applicable to any adjudicated determination of a 2006 revenue requirement, for each of the Applicants listed in Decision 2004-052, as presented below. The Board may also apply the 2006 generic ROE to any other utility that is currently, or that subsequently comes under its jurisdiction. For greater certainty, the Board notes that the 2006 generic ROE would not apply to any utility that continues to operate under final rates from a previous test year and for which there is no proceeding to establish revised final rates for 2006.

The Board may also provide additional clarification to address circumstances not covered in the preceding paragraph.

The Applicant utilities for Decision 2004-052 were:

AltaGas Utilities Inc.
AltaLink Management Ltd. (AltaLink, L.P.)
ATCO Electric Ltd. (Distribution)
ATCO Electric Ltd. (Transmission)
ATCO Gas
ATCO Pipelines
ENMAX Power Corporation (Distribution)
EPCOR Distribution Inc.
EPCOR Transmission Inc.
FortisAlberta Inc.
NOVA Gas Transmission Ltd.

2 ORDER

The Board hereby approves, in accordance with Decision 2004-052, a 2006 generic Return on Equity of 8.93%.

END OF DOCUMENT

Board Initiated Proceeding, 2007 Generic ROE Formula Result
EUB Order - U2006-292

Other Utilities – Miscellaneous
Order U2006-292 (Errata)

MADE at the City of Calgary, in the Province of Alberta, on 30th day of November 2006.	Laurie Bayda ALBERTA ENERGY AND UTILITIES BOARD

Board Initiated Proceeding 2007 Generic Return on Equity Formula Result	Application No. 1487360

The Alberta Energy and Utilities Board (Board) released *Order U2006-292: 2007 Generic Return on Equity Formula Result*, on November 27, 2006. Order 2006-292 correctly set the 2007 Generic Return on Equity at 8.51%. However, the Board has discovered that one of the inputs that it used in the formula was incorrect. The difference between the 10-year and the 30-year Canada bond yields for the month of October 2006, as reported in the National Post, was actually 0.07% rather than the 0.08% that the Board used. However, due to the effects of rounding, this input error did not affect the final result.

The corrected derivation of the formula result, with changes highlighted, is as follows:

The 3-month-out and 12-month-out forecasts of 10-year Government of Canada (Canada) yields as reported in the November 2006 Consensus Forecasts issue were 4.1% and 4.2% respectively, resulting in an average forecast 10-year Canada bond yield of 4.15% for 2007. To this forecast, the EUB added **0.07%**, representing the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October 2006, as reported in the National Post. This calculation resulted in a forecasted 2007 long-term Canada bond yield (YLD_{2007}) of **4.22%,** which is **1.46%** lower than the Board approved forecast long-term Canada bond yield of 5.68%, for the base year, 2004. Multiplying this **1.46%** differential by 0.75 produced a downward adjustment of **1.095%.** Applying this downward adjustment of **1.095%** to the 2004 ROE of 9.60% results in a generic ROE of 8.51% **(rounded to two decimal places)** for 2007. This is 0.42% lower than the 2006 generic ROE of 8.93%.

Accordingly, the amended Order U2006-292 is appended as Appendix A.

END OF DOCUMENT

APPENDIX A – AMENDED ORDER U2006-292

1 BACKGROUND AND DETAILS

The Alberta Energy and Utilities Board (Board) released *Decision 2004-052: Generic Cost of Capital*, on July 2, 2004. Decision 2004-052 set a generic rate of return on common equity (Return on Equity or ROE) of 9.60% for 2004.[1] Decision 2004-052 also approved an annual adjustment mechanism or formula for the purpose of establishing the generic ROE for 2005 and later years.

The adjustment formula set out in Decision 2004-052, at page 32, is as follows:

> $ROE_t = 9.60\% + [0.75 \times (YLD_t - 5.68\%)]$
>
> where YLD_t = the forecast long-term Canada bond yield for year t.
>
> Consistent with the approach used by the NEB, the forecast long-term Canada bond yield for year t shall be calculated as the average of the 3-month-out and 12-month-out forecasts of 10-year Canada yields as reported in the Consensus Forecasts[2] issue in November of the previous year, plus the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October in the previous year, as reported in the National Post.

The 3-month-out and 12-month-out forecasts of 10-year Government of Canada (Canada) yields as reported in the November 2006 Consensus Forecasts issue were 4.1% and 4.2% respectively, resulting in an average forecast 10-year Canada bond yield of 4.15% for 2007. To this forecast, the EUB added 0.07%, representing the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October 2006, as reported in the National Post. This calculation resulted in a forecasted 2007 long-term Canada bond yield (YLD_{2007}) of 4.22%, which is 1.46% lower than the Board approved forecast long-term Canada bond yield of 5.68%, for the base year, 2004. Multiplying this 1.46% differential by 0.75 produced a downward adjustment of 1.095%. Applying this downward adjustment of 1.095% to the 2004 ROE of 9.60% results in a generic ROE of 8.51% (rounded to two decimal places) for 2007. This is 0.42% lower than the 2006 generic ROE of 8.93%.

The 2007 generic ROE is applicable to any adjudicated determination of a 2007 revenue requirement, for each of the Applicants listed in Decision 2004-052, as presented below. The Board may also apply the 2007 generic ROE to any other utility that is currently, or that subsequently comes under its jurisdiction. For greater certainty, the Board notes that the 2007 generic ROE would not apply to any utility that continues to operate under final rates from a previous test year and for which there is no proceeding to establish revised final rates for 2007.

The Board may also provide additional clarification to address circumstances not covered in the preceding paragraph.

[1] Page 31
[2] Published by Consensus Economics Inc., London, England

The Applicant utilities for Decision 2004-052 were:

AltaGas Utilities Inc.
AltaLink Management Ltd. (AltaLink, L.P.)
ATCO Electric Ltd. (Distribution)
ATCO Electric Ltd. (Transmission)
ATCO Gas
ATCO Pipelines
ENMAX Power Corporation (Distribution)
EPCOR Distribution Inc.
EPCOR Transmission Inc.
FortisAlberta Inc.
NOVA Gas Transmission Ltd.

2 ORDER

The Board hereby approves, in accordance with Decision 2004-052, a 2007 Generic Return on Equity of 8.51%.

END OF DOCUMENT

Other Utilities – Miscellaneous
Order U2006-292

MADE at the City of Calgary, in the Province of Alberta, on 27th day of November 2006.	Laurie Bayda ALBERTA ENERGY AND UTILITIES BOARD

Board Initiated Proceeding 2007 Generic Return on Equity Formula Result	Application No. 1487360

1 BACKGROUND AND DETAILS

The Alberta Energy and Utilities Board (Board) released *Decision 2004-052: Generic Cost of Capital*, on July 2, 2004. Decision 2004-052 set a generic rate of return on common equity (Return on Equity or ROE) of 9.60% for 2004.[1] Decision 2004-052 also approved an annual adjustment mechanism or formula for the purpose of establishing the generic ROE for 2005 and later years.

The adjustment formula set out in Decision 2004-052, at page 32, is as follows:

> $ROE_t = 9.60\% + [0.75 \text{ x } (YLD_t – 5.68\%)]$
>
> where YLD_t = the forecast long-term Canada bond yield for year t.
>
> Consistent with the approach used by the NEB, the forecast long-term Canada bond yield for year t shall be calculated as the average of the 3-month-out and 12-month-out forecasts of 10-year Canada yields as reported in the Consensus Forecasts[2] issue in November of the previous year, plus the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October in the previous year, as reported in the National Post.

The 3-month-out and 12-month-out forecasts of 10-year Government of Canada (Canada) yields as reported in the November 2006 Consensus Forecasts issue were 4.1% and 4.2% respectively, resulting in an average forecast 10-year Canada bond yield of 4.15% for 2007. To this forecast, the EUB added 0.08%, representing the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October 2006, as reported in the National Post. This calculation resulted in a forecasted 2007 long-term Canada bond yield (YLD_{2007}) of 4.23%, which is 1.45% lower than the Board approved forecast long-term Canada bond yield of 5.68%, for the base year, 2004. Multiplying this 1.45% differential by 0.75 produced a downward adjustment of 1.09% (rounded to two decimal places). Applying this downward adjustment of

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1.09% to the 2004 ROE of 9.60% results in a generic ROE of 8.51% for 2007. This is 0.42% lower than the 2006 generic ROE of 8.93%

The 2007 generic ROE is applicable to any adjudicated determination of a 2007 revenue requirement, for each of the Applicants listed in Decision 2004-052, as presented below. The Board may also apply the 2007 generic ROE to any other utility that is currently, or that subsequently comes under its jurisdiction. For greater certainty, the Board notes that the 2007 generic ROE would not apply to any utility that continues to operate under final rates from a previous test year and for which there is no proceeding to establish revised final rates for 2007.

The Board may also provide additional clarification to address circumstances not covered in the preceding paragraph.

The Applicant utilities for Decision 2004-052 were:

AltaGas Utilities Inc.
AltaLink Management Ltd. (AltaLink, L.P.)
ATCO Electric Ltd. (Distribution)
ATCO Electric Ltd. (Transmission)
ATCO Gas
ATCO Pipelines
ENMAX Power Corporation (Distribution)
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EPCOR Transmission Inc.
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2 ORDER

The Board hereby approves, in accordance with Decision 2004-052, a 2007 Generic Return on Equity of 8.51%.

END OF DOCUMENT

TGI TGVI Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism
BCUC Decision March 2006

IN THE MATTER OF

TERASEN GAS INC. AND
TERASEN GAS (VANCOUVER ISLAND) INC.
APPLICATION TO DETERMINE THE APPROPRIATE
RETURN ON EQUITY AND CAPITAL STRUCTURE
AND TO REVIEW AND REVISE THE
AUTOMATIC ADJUSTMENT MECHANISM

DECISION

MARCH 2, 2006

Before:

R.H. Hobbs, Panel Chair
R.J. Milbourne, Commissioner
A.J. Pullman, Commissioner

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1.0 EXECUTIVE SUMMARY

On June 30, 2005, Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") applied to the Commission to determine the appropriate return on equity and capital structure and to review and revise the automatic adjustment mechanism. TGI's return on equity and capital structure were established following a generic hearing by the Commission in 1994, at 350 basis points over the forecast long Canada bond yield and an equity component of 33 percent. The automatic adjustment mechanism was amended in 1999, with the result that when long Canada bond yields are forecast to be below 6 percent, the ROE rises and falls in step with the forecast long Canada bond yield. TGI has the lowest return on equity and smallest equity component of capital structure of any gas distribution company in Canada.

Up to 2002 TGVI's return on equity and capital structure were established by Special Direction issued by the Lieutenant Governor in Council to the Commission. Thereafter, under the Commission's negotiated settlement process, they were determined to be a 50 basis point premium over the return on equity of the benchmark low-risk utility (which the Commission determined to be TGI) and an equity component of 35 percent.

The Applicants seek the following returns on equity (based on the November 2006 consensus long Canada bond yield forecast of 4.79 percent) and equity component:

TGI	10.16%	38%
TGVI	10.91%	40%

The Commission Panel determines that both the comparable earnings standard and the capital attraction standard are equally relevant in establishing a fair return.

Accordingly, the Commission Panel gives weight to both the Equity Risk Premium and the Discounted Cash Flow approaches to establishing a fair rate of return. It is unable to give any weight to the Comparable Earnings of low-risk Canadian industrials in this proceeding, although it believes that this approach may play a role in future hearings.

The Commission Panel concludes that the appropriate return on equity for a benchmark low-risk utility is 3.90 percent over the forecast long Canada bond yield. The Commission Panel determines that TGI will continue to be the benchmark low-risk utility. The Commission Panel also concludes that a revision to the automatic adjustment mechanism is appropriate, such that the return on equity will be adjusted by 75 percent of the change in forecast long Canada bond yields, effective January 1, 2006. Accordingly, the return on equity for

TGI for 2006 will be 8.80 percent and its equity component will be 35 percent. For TGVI the Commission Panel determines that a 70 basis point premium over the benchmark low-risk utility is appropriate for a return for 2006 of 9.50 percent, and an equity component of 40 percent.

2.0 INTRODUCTION AND BACKGROUND

2.1 Introduction

On June 30, 2005 Terasen Gas Inc. ("Terasen Gas" or "TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") collectively referred to as the "Companies" or the "Applicants" jointly filed an application (the "Application" with the British Columbia Utilities Commission ("BCUC" or the "Commission") to determine the appropriate return on equity ("ROE") and capital structure, and to review and revise the automatic adjustment mechanism ("AAM").

2.2 Overview

2.2.1 TGI

In 1994 the Commission was the first in Canada to hold a generic hearing into the appropriate rates of return on common equity and capital structure for utilities subject to its jurisdiction. It determined BC Gas Utility Ltd. ("BC Gas") (now Terasen Gas Inc.) to be the benchmark low-risk utility and established rates of return on common equity and capital structure for BC Gas, West Kootenay Power Ltd. (now FortisBC Inc.) and Pacific Northern Gas Ltd. ("PNG"). In addition, its Order No. G-35-94 established an AAM for calculating the allowed ROE on an annual basis.

In 1997 the Commission, by Order No. G-49-97, amended the AAM to correct for certain problems and to make it more consistent with the practices of other Canadian jurisdictions. In that Order the Commission directed that the range of forecast long Canada bond yields over which the AAM would apply would be 6.0 percent to 12.0 percent.

In November or December of each year from 1995 through 1998 the Commission issued letters to the Utilities subject to its jurisdiction establishing the ROE allowed for rate making purposes for each subsequent year based on calculations pursuant to the AAM. Centra Gas British Columbia's (now TGVI) ROE was set by Special Direction during that period.

In 1999, following an oral public hearing into the ROE for a low-risk benchmark utility and into the AAM, the Commission issued Order No. G-80-99, which directed that the AAM should continue to be employed, with certain exceptions:

- at forecast long Canada yields of 6.0 percent or below, the equity risk premium for a low-risk benchmark utility will be fixed at 350 basis points;

- at forecast long Canada yields of greater than 6.0 percent, the current contraction/expansion factor (i.e., the sliding scale) of 0.8 of the difference in forecast long Canada yields shall be retained and shall be driven off a low-risk benchmark utility ROE of 9.5 percent;

- to determine the forecast long Canada yield, the period over which the 10- to 30-year spread is to be measured shall be redefined as all the trading days in the October preceding the November Consensus forecast; and

- the Commission will canvass interested parties on the need for a review of the automatic adjustment formula when long Canada rates exceed 8.0 percent for a period of at least six months.

On November 1, 2000, BC Gas applied to the Commission to adjust the application of the automatic ROE adjustment formula to address the then current situation of yields on 10-year Government of Canada bonds exceeding the yields on 30-year Government of Canada bonds. The Commission reviewed the submissions of the various parties and decided not to vary the application of the ROE adjustment mechanism for 2001, as stated in Letter No. L-61-00.

In Letter No. L-62-01 the Commission established a written public hearing to review the yield spread between medium and long-term bonds in 2001 to consider whether amendments should be made to the mechanism for 2002. Following that written proceeding, the Commission determined by Order No. G-109-01 that the treatment of the yield spread between 30-year and 10-year bonds did not require adjustment. The Commission also determined that the ROE for the benchmark low-risk utility, expressed as a percentage, should be rounded to two decimal places prior to adding the utility-specific risk premium.

On July 22, 2004, TGI wrote to the Commission requesting the Commission convene a hearing to review return on equity and capital structure. By Order No. G-88-04 the Commission determined that a hearing was not warranted at that time but concluded that such a review may be appropriate in the Fall of 2005 in time for implementation January 1, 2006.

By Application dated June 30, 2005, the Companies submit that since 1994, when the Commission introduced its ROE adjustment mechanism for setting rates of returns, which reflected the economic climate and circumstances of the day, much has changed and that in British Columbia, in Canada and in North America there is intense competition for capital.

The Applicants ask the Commission to move in accordance with these changed circumstances and recognize that it is not appropriate to subject investors in TGI to the lowest allowed return on equity in Canada.

Further the Applicants ask that the Commission recognize that British Columbia utilities must compete for capital with other Canadian utilities and with utilities in the U.S. and award returns on equity, and establish capital structures, that are appropriate in today's financial markets and reflect the business and financial risks of the utilities in British Columbia.

TGI requests that the Commission acknowledge changed circumstances by allowing it a common equity component of 38 percent in its capital structure, and a return on equity of 10.50 percent when long-term Canada bonds are forecast to yield 5.25 percent. TGVI requests that it be allowed a common equity component of 40 percent and be granted an additional 75 basis point increment over the allowed return on equity of TGI (i.e., 11.25 percent when the forecast yield on long-term Canada bonds is 5.25 percent).

Finally, the Applicants ask that the AAM be revised to make it comparable with other Canadian jurisdictions, both federal and provincial, which have established a sliding scale adjustment of 0.75:1 through its entire range of application.

On August 3, 2005, the Commission held a Procedural Conference, pursuant to Order No. G-69-05, to address the scope of the Commission's review of the Application, the steps and timetable associated with the regulatory review process and any other matters to assist the Commission to efficiently review the Application.

With input provided by Utilities and Intervenors at the Procedural Conference, the Commission defined the scope of the proceeding as follows:

1) The automatic ROE adjustment mechanism and all issues related thereto with respect to the establishment of the low-risk benchmark utility return used in the calculation of the appropriate ROE for utilities;

2) The capital structure for TGI and TGVI and utility-specific risk premium, if any, used in the calculation of the appropriate ROE for TGI and TGVI; and

3) The date the decision becomes effective.

A public hearing was held in Vancouver on November 14-18, 2005. Written Argument and Reply were received by January 5, 2006. Supplementary oral argument was heard by the Commission Panel on January 17, 2006.

2.2.2 TGVI

Under the terms of the Special Direction to the Commission issued under the Vancouver Island Natural Gas Pipeline Act ("VINGPA") by the Lieutenant Governor in Council through Order in Council 1510/95 the equity component of the capital structure and return on equity were set at 35 percent and 362.5 basis points over the long Canada bond yield respectively until December 31, 2002, after which time the Commission would set rates in accordance with the regulatory principles that are generally applied by it from time to time to gas distribution companies operating within British Columbia. In 2001 BC Gas Inc. (now Terasen Inc. or "TI") acquired Centra Gas British Columbia Inc. In 2003, in accordance with the negotiated settlement, the Commission approved by Order No. G-2-03 that TGVI's equity component of capital structure would be 35 percent and its ROE set at a premium of 50 points basis over the benchmark low-risk utility ROE.

2.2.3 The Law and the Jurisdiction of the Commission

Intervenors and Applicants cite four court decisions that they submit are relevant to the matters in this proceeding: *B.C. Electric Railway Co. Ltd. v. Public Utilities Commission of B.C. et al.* [1960] S.C.R. 837 ("*B.C. Electric Railway*"), *Hemlock Valley Electrical Services Ltd. v. BCUC* (1992) 66 B.C.L.R. (2d) 1 (B.C.C.A.) ("*Hemlock Valley"), Bell Canada v. Canada* (CTRC) [1989] 1 S.C.R. 1722 ("*Bell Canada*"), and *Northwestern Utilities Ltd. v. Edmonton and Board of Public Utility Commissioners of Alberta* [1929] S.C.R. 186 *("Northwestern Utilities").*

In addition, the B.C. Old Age Pensioners' Organization et al. ("BCOAPO") reminds the Commission of its duties under the Utilities Commission Act ("Act", "UCA") in setting just and reasonable rates. These are:

1. a fair and reasonable charge for service of the nature and quality provided by the utility,
2. sufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, and
3. not unjust or unreasonable for any other reason [Utilities Commission Act ("UCA"), s. 59].

The Applicants submit that the *B.C. Electric Railway* and the *Hemlock Valley* cases make it clear that the obligation to allow a utility to earn a fair and reasonable return is absolute, and that a rate is unjust or unreasonable if it fails to yield a just and reasonable return on rate base (TGI/TGVI Submissions, p. 34, para. 115).

The BCOAPO cites *Bell Canada* and *Northwestern Utilities* and submits that the Commission must balance the interests of customers to a fair and reasonable charge for services with the interests of shareholders to fair and reasonable compensation. The BCOAPO submits that the Commission should take into account the rate increases that would result if the Application is approved (BCOAPO Submission, p. 7).

The Joint Industry Electrical Steering Committee ("JIESC") submits that all of the resources TGI and TGVI require, including the capital, must be obtained at the lowest possible cost and that the return must be equal to the returns available to investors on investments of comparable risk (JIESC Submission, p. 3; T7: 995).

The Commercial Energy Consumers Association of British Columbia ("CEC") submits that the obligation to allow a utility to earn a fair and reasonable return on rate base is not absolute, and that the Commission must balance the interests of customers and shareholders. The CEC further submits that if the obligation to allow a utility to earn a fair and reasonable return on rate base is absolute it would entitle new shareholders, who have paid a premium to departing shareholders of a regulated utility, to request a fair return on their investment, including any premium paid for the investment (CEC Submission, pp. 2-3).

<u>Commission Determinations</u>

The Commission's mandate is to ensure that ratepayers receive safe, reliable and non-discriminatory energy services at fair rates from the public utilities it regulates, and that shareholders of those public utilities are afforded a reasonable opportunity to earn a fair return on their invested capital. The process to establish a fair return and just and reasonable rates is enshrined in the UCA where "the commission must consider all matters that it considers proper and relevant affecting the rate" and in doing so it must have due regard to the setting of a rate that "is not unjust or unreasonable" within the meaning of section 59 (of the Act) [*UCA*, s.60 (1)(a) and (b)(i)].

The reasons of Locke J. and Martland J. in the *B.C. Electric Railway* case are ad idem on the matter of the need to consider both the costs of providing service and a fair return on invested capital used or prudently incurred to provide the service. First Locke J. said:

> "…I do not think it is possible to define what constitutes a fair return upon the property of utilities in a manner applicable to all cases or that it is expedient to attempt to do so. It is a continuing obligation that rests upon such a utility to provide what the Commission regards as adequate service in supplying not only electricity but transportation and gas, to maintain its properties in a satisfactory state to render adequate service and to provide extensions to these services when, in the opinion of the Commission, such are necessary. In coming to its conclusion as to what constituted a fair return to be allowed to the appellant these matters as well as the undoubted fact

> that the earnings must be sufficient, if the company was to discharge these statutory duties, to enable it to pay reasonable dividends and attract capital, either by the sale of shares or securities, were of necessity considered. Once that decision was made it was, in my opinion, the duty of the Commission imposed by the statute to approve rates which would enable the company to earn such a return or such lesser return as it might decide to ask" (Exhibit A3-5, p. 848).

Martland J. said:

> "The rate to be imposed shall be neither excessive for the service nor insufficient to provide a fair return on the rate base. There must be a balancing of interests. In my view, however, if a public utility is providing an adequate and efficient service [as it is required to do by s. 5 of the Act (now s. 38)], without incurring unnecessary, unreasonable or excessive costs in so doing, I cannot see how a schedule of rates, which, overall, yields less revenue than would be required to provide that rate of return on its rate base which the Commission has determined to be fair and reasonable, can be considered, overall, as being excessive" (Exhibit A3-5, p. 856).

The submissions of the Applicants and the Intervenors in this proceeding are not ad idem regarding the appropriate consideration of the "balancing of interests". The Commission Panel finds the reasons of Locke J. and Martland J. instructive, and notes that they are accepted in the *Bell Canada* case. The Commission Panel does not accept that the reference by Martland J. to a "balancing of interests" to mean that the exercise of determining a fair return is an exercise of balancing the customers' interests in low rates, assuming no detrimental effects on the quality of service, with the shareholders' interest in a fair return. In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital. As Martland J. said, "The rates to be imposed shall be neither excessive for the service nor insufficient to provide a fair return on rate base." With the use of AAM, the determination of the cost of service and the determination of a fair return are now issues for separate processes.

As for the JIESC's lowest cost argument, the Commission Panel shares the view of the NEB, which recognized that "lowest possible" was not the appropriate test when it stated, at page 25 of its RH-2-94 Decision on generic cost of capital:

> "Contrary to what some parties advocated during the hearing, the Board is of the view that it is not appropriate to over-leverage a pipeline in order to identify the minimum acceptable deemed common equity ratio possible."

2.3 The Applications

2.3.1 Benchmark low-risk utility

The Applicants seek revised capital structures and a return on equity appropriate to a benchmark low-risk utility.

TGI (then BC Gas Utility Ltd.) was deemed the benchmark utility in 1994 when the first generic ROE adjustment mechanism was established, and has continually been regarded as such by the Commission (Exhibit B-1, Tab 1, p. 2).

TGI's expert witness, Ms. McShane, describes a "benchmark low-risk utility" as a hypothetical construct. She considers that one objective measure of what constitutes a low-risk utility would be the utility's ability, on a stand-alone basis, to achieve debt ratings of A. In her view "The benchmark return is derived from data for utilities across industries (electric, gas distribution and gas pipeline), as well as from data for non-utilities. It is based on no specific utility and hence reflects no specific business or financial risk characteristics" (Exhibit B-1, Tab 2, p. 11).

2.3.2 Basis for filing the Applications

According to the Companies, the basis for the filing of the Applications is:

1) The AAM has resulted in TGI being allowed the lowest return on investment of any regulated energy utility in Canada.

2) The AAM has had unintended consequences when forecast long Canada bond yields are below 6 percent.

3) There have been significant changes in the Canadian economy and financial markets since 1994.

4) The business risk profile of TGI has changed since 1994, while its capital structure has been weakened by the elimination of preferred shares.

5) The capital structure and ROE should enable the companies to maintain adequate debt coverage ratios to avoid alarms from debt rating agencies.

6) The Commission should give weight to all three methods of determining the cost of equity capital namely the Equity Risk Premium, the Discounted Cash Flow and the Comparable Earnings tests (Exhibit B-1, pp. 2-3).

2.3.3 TGI

TGI states that in order to be designated the benchmark low-risk utility, it requires a common equity component in the capital structure of 38 percent as compared to the current 33 percent and a ROE of 10.5 percent when long Canada bonds are forecast to yield 5.25 percent (Exhibit B-1, Cover Letter, p. 3; TGI/TGVI Submissions, p. 1). Based on the consensus long Canada bond yield forecast of 4.79 percent the determination of the formula-based allowed ROE for 2006 is 8.29 percent (Exhibit B-25; B-26). The Applicants submit that any variance from a long-term Canada forecast bond yield of 5.25 percent should be accommodated through an adjustment in the ROE by 75 percent of the variance of long-term Canada bond forecast. On this basis, the 2006 ROE for TGI should be set at 10.16 percent [10.5%-(.75*(5.25-4.79))] (TGI/TGVI Submissions, p. 26; TGI/TGVI Reply Submissions, p. 46).

2.3.4 TGVI

TGVI seeks a common equity ratio of 40 percent and equity risk premium relative to the benchmark low-risk utility of 75 basis points. The current common equity component of TGVI is 35 percent and the premium is 50 basis points relative to the benchmark utility (Exhibit B-1, Tab 2, p. 18; Exhibit B-3, BCUC IR 40.1; Exhibit B-14A; TGI/TGVI Argument, pp. 32, 33). The determination of the formula-based 2006 allowed ROE for TGVI is 8.79 percent (Exhibit B-26). TGVI submits that its ROE should be set at 10.91 percent (i.e., 10.16 percent plus 75 basis points) (TGI/TGVI Submissions, p. 62; TGI/TGVI Reply Submissions, p. 46).

2.4 Acquisition of Terasen Inc. by Kinder Morgan, Inc.

The Applicants filed their application with the Commission on June 30, 2005. On August 1, 2005 Kinder Morgan, Inc. (“KMI”) and Terasen Inc., the sole shareholder of the Applicants, announced a definitive agreement whereby KMI would acquire all of the outstanding shares of TI for $35.91 per share. This amount is 2.7 times the book value of each TI share. The total purchase price, including the assumption of debt, is announced to be $6.9 billion. Following the announcement of the transaction Moody’s Investors Service announced that it would place TGI on credit watch with negative implications until it had investigated the implications of the transaction on TGI’s credit quality. Moody’s Investors Service downgraded TGI on December 19, 2005, stating that it had evaluated TGI’s credit on a stand-alone basis assuming that the regulatory ring-fencing imposed by the Commission would be effective in insulating TGI from the higher business and financial risk of its parent entities (Exhibit B-27, p. 1).

The Applicant's treasurer, Mr. Bryson commented on the transaction:

> "Well, I think that 2.7 book value was for the entire Terasen entity, which includes not just the gas utility business, but includes the pipeline business and the water business. You know, as we've indicated to investors over the past several years and demonstrated to investors over the last several years, we've got tremendous growth potential in our pipelines business…I think, you know, their public statements are clear that they saw the greatest potential in the pipelines business. When you add up the various growth opportunities that Terasen has in front of it, I mean, we're a $5-billion organization currently, with more that $5 billion of growth potential in that business segment alone" (T2: 123).

On August 17, 2005, KMI applied to the Commission under section 54 of the UCA for approval of the acquisition of the shares of TI. On November 10, 2005 the Commission approved the transaction, subject to certain conditions concerning "ring-fencing," independent governance and location of data. The ring-fencing provisions are designed to insulate TGI and TGVI from credit rating downgrades and related financial risks associated with any affiliates in the large Terasen/KMI corporate family. The conditions approved by the Commission are as follows:

1) Each Terasen Utility shall maintain, on a basis consistent with BCUC orders and accounting practices, a percentage of common equity to total capital that is at least as much as that determined by the Commission from time to time for ratemaking purposes.

2) No Terasen Utility will pay a common dividend without prior Commission approval if the result would reasonably be expected to violate the restriction in (1) above.

3) (a) No Terasen Utility will lend to, guarantee or financially support any affiliates of the Terasen Utilities, other than between TGI and TGS, or as otherwise accepted by the Commission.

   (b) TGI and TGS shall together maintain separate banking and cash management arrangements from other affiliates. TGVI shall establish separate banking and cash management arrangements from other affiliates once it has completed its proposed refinancing.

   (c) No Terasen Utility will enter into a tax sharing agreement with any affiliate of the Terasen Utility, unless the agreement has been approved by the Commission.

4) No Terasen Utility will enter into transactions with affiliates that are not in compliance with Commission guidelines, policies or directives regarding affiliate transactions, and no Terasen Utility will enter into transactions with affiliates on terms less favourable to the Terasen Utility than those available from third parties on an arms-length basis, unless otherwise approved by the Commission.

5) No Terasen Utility will engage in, provide financial support to or guarantee non-regulated businesses, unless otherwise approved by the Commission.

The intervenors filed the evidence of Dr. Booth on October 11, 2005. Dr. Booth summarizes his evidence with the following observation:

> "Kinder Morgan's (KMI) proposed takeover of Terasen Inc. is at an 11.8X expected 2006 EBITDA or 2.7X book value. This extreme valuation implies that the financial parameters applied to the Terasen companies are extremely generous and confirms my judgment that they should be reduced. The KMI takeover also calls into question the lack of ring fencing of Terasen Gas and the need for restrictions on inter affiliate cash management and transactions. Failing such ring fencing, in the face of the double leverage used by KMI to finance the transaction, there is a grave risk that Terasen Gas Inc.'s bond rating will suffer and ratepayers will be paying unfair and unreasonable debt costs" (Exhibit C2-6, p. 3).

Dr. Booth refers to a CIBC World Markets report dated August 19, 2005 that claims KMI plans a "double dip" financing structure, which would enable it to claim interest as an expense in both Canada and the U.S. which would result in lower taxes being paid by the new group (Exhibit C2-6, p. 83).

BCOAPO argues that the gas distribution companies were an integral reason that a premium was paid by KMI. This position is based on the expert evidence of Dr. Booth, who testified that because TGI represents 65 percent of the earnings of TI, "part of that 2.7 times clearly reflects the fact that they were happy with Terasen Gas" (BCOAPO Argument, p. 10).

The CEC argues that the KMI purchase at its high valuation is conclusive evidence in and of itself that the existing ROE and debt/equity structure is delivering a more than fair, just and reasonable return to departing shareholders and the new shareholders involved in the purchase (CEC Submission, p. 3).

The JIESC takes the position that when the allowed return equals the investors required return, the market to book ratio will be equal to one. The Intervenor cautions that if the ROE is set too generously, the market to book ratio will rise and the customers will pay more than is necessary to attract capital (JIESC Submission, p. 4).

The Companies in Reply Argument clarify that the KMI acquisition did not cause any change in the shareholding of either TGI or TGVI as the shares of both companies continue to be owned by TI. The Companies argue that the CEC was incorrect to suggest that TGI and TGVI are seeking to recover the premium over book value that KMI paid on the purchase of the shares of TI, and that there is no support for the Intervenors' argument that the new shareholder of TI was satisfied with the current ROE (TGI/TGVI Reply Submissions, pp. 6-7).

The Companies submit that the acquisition of TI by KMI should play no part in the Commission's determination of the requests for relief that was made in the Applications. The Companies argue that the Commission cannot infer that KMI was satisfied with the return that was in place (T7: 1031).

Commission Determinations

In considering the premium paid by KMI for the shares of TI, the Commission Panel is cognizant of the findings of the Alberta Energy Utility Board ("AEUB") in its Generic Cost of Capital Decision, July 2, 2004 (Exhibit A3-1, p. 28):

> "The Board also agrees that there may be strategic factors affecting the price that is paid to acquire a utility. The Board also recognizes that, in some cases, a premium might be paid for regulated assets in anticipation of significant future growth in rate base, to achieve geographic diversification or to obtain a foothold in a new market. The Board is not aware of the strategic factors that may have affected the price paid to acquire Alberta utilities in recent years."

The Commission Panel is aware of a number of strategic and fiscal factors that may have affected the price paid by KMI for the shares of TI. KMI can employ double leverage and can claim interest expenses in both the U.S. and Canada ("the double dip") to make the acquisition earnings accretive. TI's oil transportation business has significant growth opportunities. To protect the financial integrity of TI's gas distribution subsidiaries the Commission has initiated "ring-fencing" conditions. The Commission notes that Moody's Investors Service has announced that it is satisfied with the "ring-fencing" conditions imposed by the Commission and that the downgrading by Moody's of TGI was unrelated to the transaction. There is no evidence before the Commission that any of the premium paid by KMI will be included in either of the Companies' rate bases and recovered from their customers. The Commission's role is to determine a suitable capital structure for the Applicants and return on equity for a benchmark low-risk utility and the KMI/TI transaction is not relevant to the Commission's determination.

3.0 AUTOMATIC ADJUSTMENT MECHANISM

3.1 Evidence and Argument

TGI has applied to change the contraction/expansion factor (or “sliding scale”) component of the Commission’s AAM such that the ROE will be adjusted by 75 percent of the change in forecast long Canada bond yields.

In 1994 the Commission implemented an adjustment mechanism for annually setting returns on equity, with revisions to the mechanism in the interim, including in 1999 as part of the Commission’s 1999 ROE and Capital Structure Decision. The current mechanism increases the annual allowed return on equity by 80 percent of the change in forecast long Canada yields above 6.0 percent, and reduces the annual allowed return on equity by 100 percent of the change in forecast long Canada yields below 6.0 percent. Through its 1999 Decision the Commission also established that it would canvass interested parties on the need for a review of the automatic adjustment formula when long Canada rates exceed 8.0 percent for a period of at least six months.

Ms. McShane recommends that the Commission implement a symmetric 75 percent sliding scale, which she states would recognize that interest rates and the cost of equity do not rise and fall in tandem. She also submits that a 75 percent sliding scale would recognize the validity of the objectives of maintaining a stable financial profile and stable rates, and would put B.C. utilities on a similar footing as their Canadian peers (Exhibit B-1, Tab 2, p. 100). In support of her recommendation, Ms. McShane points to the results of her DCF-based equity risk premium test, which she concludes suggests that the utility cost of equity is less sensitive to changes in government bond yields than implied by the current sliding scale. In support, Ms. McShane also refers to her evidence of an average 75 percent ratio of Canadian utility dividend yields to long Canada bond yields in the period 1996-2004 as well as to her demonstration that a one percentage point change in the before-tax yield on a long-term Canada bond requires roughly a 70 basis points change in the utility return on equity to maintain a similar after-tax equity risk premium (Exhibit B-1, Tab 2, pp. 98-99).

Ms. McShane recommends that the formula should be reviewed if forecast long Canada yields fall below 4 percent or exceed 8 percent on the basis that long Canada yields outside of the range of 4.0-8.0 percent may indicate a materially altered relationship between long Canada yields and the utility cost of equity (Exhibit B-1, Tab 2, p. 100).

TGI submits that the current BCUC adjustment mechanism increasingly disadvantages B.C. utilities as long Canada bond yields decline, being the only such mechanism that provides for a one to one relationship between bond yields and allowed returns on equity (TGI/TGVI Submissions, p. 64). The Companies submit that the "penalization" of B.C. utilities can only be rectified by establishing a fair and reasonable return and implementing an adjustment formula with a symmetrical 75 percent sliding scale (TGI/TGVI Submissions, p. 64).

While Dr. Booth is not aware of any research to justify adjustment coefficients of either 0.75 or 0.80, and does not believe that risk premiums vary in a mechanical fashion with interest rates, he does support adjustment mechanisms as balancing the interests of shareholders and consumers and providing a viable compromise that avoids annual repetitive rate hearings. Dr. Booth judges that whether the adjustment coefficient is 0.75 or 0.80 is not material, but submits that that these coefficients are in the right range (Exhibit C2-6, pp. 67-68).

Dr. Booth recommends a sliding scale with an adjustment coefficient of 0.75. Dr. Booth has not specified any range in long Canada yields outside of which the formula should be reviewed since such cut-off points depend heavily on the economic situation that generates them, which cannot be specified ahead of time. Instead, Dr. Booth relies on the company, intervenors and Board staff to decide when a hearing is needed, based on their analysis of ongoing economic events (Exhibit C2-7, p. 85).

The JIESC accepts Dr. Booth's recommendation to change the adjustment mechanism after the benchmark return is reset so that for future changes being made pursuant to the adjustment mechanism, the return on equity is raised or lowered by 75 basis points for every 100 basis points change in long-term Canada yields (JIESC Submission, p. 40).

Other intervenors either made no submission on the sliding scale component of the AAM, or adopted the evidence of Dr. Booth and the submissions of the JIESC.

Commission Determinations

The Commission Panel notes that aside from recommended changes to the sliding scale component of the AAM, no other changes were recommended, such as to the method used to determine the forecast long Canada bond yield.

The Commission Panel is satisfied with the reasonableness of the proposed changes to the sliding scale recommended by TGI and supported by Intervenors. The Commission Panel approves a change to the adjustment mechanism such that the benchmark return on equity is raised or lowered by 75 percent of the change in the forecast long Canada bond yield.

The Commission Panel calculates that the result of this adjustment will be to increase the ROE for the benchmark low-risk utility for 2006 from 8.29 percent to 8.60 percent. The determination of the appropriate ROE is discussed in Section 6.

3.2 Review Process

Neither the Applicants nor the Intervenors make any recommendations concerning a periodic review of the process, or concerning events that should trigger such a review. In light of the AEUB finding in its 2004 Generic Cost of Capital Decision, the Commission Panel will adopt a review period of five years, while noting that any party continues to be free at any time to apply to the Commission to consider a review of the AAM. In addition, should the AAM result in a ROE for the benchmark low-risk utility of less than 8 percent or greater than 12 percent the Commission will canvass the views of the parties on whether the AAM should be reviewed.

4.0 RISK

4.1 Risk Defined

The Applicant and Intervenors broadly agree on the definition of risk to a benchmark low-risk utility. Investment risk comprises the sum of business risk, financial risk and regulatory risk.

Business risk is the risk that the utility will not be able to earn a return on its capital or of its capital. Dr. Booth summarized those elements that constitute business risk as:

> "…stemming from uncertainty in the demand for the firm's product resulting, for example, from changes in the economy, the actions of competitors, and the possibility of product obsolescence. This demand uncertainty is compounded by the method used by the firm and the uncertainty in the firms' cost structure, caused, for example, by uncertain input costs, like those for labour or critical raw or semi-manufactured materials" (Exhibit C2-6, p. 22, line 13).

Financial risk is measured through the debt equity ratio of a utility (Exhibit C2-6, p. 23).

Regulatory risks are those that might arise from regulatory lag, from disallowed operating or capital costs or from punitive awards.

4.2 TGI

4.2.1 <u>TGI's Submission</u>

TGI submits that since the generic hearing and the introduction of the AAM in 1994 the competitive environment in which it operates has greatly changed, and that its business risks have increased significantly. The Companies identify nine components to the increase in the business risks of TGI and TGVI.

1) The operating cost advantage of natural gas versus other energy sources has declined; TGI provides Exhibit B-6 to illustrate a narrowing of the gap between gas and electricity for its residential customers in the Lower Mainland and Central interior of the province.

2) TGI's gas versus electricity price advantage is the lowest among Canadian gas distribution companies. Table 1 on page 7 of Exhibit B-1, Tab 1 shows gas to have a considerable price advantage over electricity in Alberta and Ontario.

3) Price competitive trends have led to declining captive rates for new customers. In addition to a greater proportion of new construction being multifamily dwelling, where TGI has experienced lower capture rates, TGI is experiencing reduced capture rates in single-family homes and estimates

its capture rate to have declined by 10 percent from the low 90 percent to the low 80 percent (Exhibit B-3, p. 64).

4) Alternative energy sources are more prevalent now than in the early 1990s. TGI cites ground source heat pumps in the residential sector, and industrial customers' ability to switch fuel types.

5) The annual use of natural gas by residential customers has declined through the 1990s and is forecast to continue to decline in the future; TGI states that residential use declined by 12.5 percent between 1997 and 2004, with a further 2 percent decline forecast to occur by 2009 (Exhibit B-1, Tab 1, p. 12-4). In Exhibit B-2, page 43, TGI notes that despite lower average consumption, its residential customers are paying more for use of natural gas.

In addition, TGI files data regarding its actual volumes sold and transported, which show a considerable decline:

Recorded Actual TGI Volumes – TJs

	Sales	**Transport**	**Total**
1995	124,856	56,426	181,282
1996	144,084	60,377	204,461
1997	135,866	58,305	194,171
1998	129,537	58,304	187,841
1999	136,150	63,382	199,532
2000	135,216	62,268	197,484
2001	120,553	58,806	179,359
2002	124,260	64,169	188,429
2003	113,391	62,415	175,806
2004	109,799	62,914	172,713

Notes
1. Includes Fort Nelson
2. Sales includes rates 1-7
3. Transport includes rates 22-27, excludes BC Hydro and TGVI Wheeling volumes (Exhibit B-12)

6) Changes in the gas supply environment have required TGI to become very proactive in the regional gas market and to develop strict controls on acceptable transactions and credit positions with external counterparties; TGI notes that it has proposed to extend its hedging program from 24 to 36 months. This necessitates larger credit lines to support mark to market losses on forward positions, and the need to contract only with creditable counterparties (Exhibit B-1, Tab 1, pp. 15-16).

7) TGI is limited in its ability to pass costs through because of the competitive pressure from other energy sources; this has required it to invest in software applications, which enable it to capture productivity gains (Exhibit B-3, p. 77).

8) Potential accounting changes for rate regulated enterprises, such as the elimination of accounting for regulatory deferral accounts, could introduce significant volatility into the earnings of such businesses and negatively impact compliance with excessive covenants and the ability to attract capital in the future (Exhibit B-1, Tab 1, p. 17).

9) TGI rejects the suggestion that deferral accounts eliminate or substantially reduce its business risk. Almost all utilities in North America now have energy cost deferral accounts and many have weather normalization accounts. This was not the case in 1994 when TGI was deemed to be the benchmark low-risk utility. TGI claims that, when compared to other regulated utilities, it is inappropriately designated as a "benchmark low-risk utility" (Exhibit B-1, Tab 1, pp. 17-18).

Ms. McShane, the Applicant's witness, submits that a 33 percent common equity ratio is too low for TGI to be considered equivalent to the benchmark low-risk utility. Her conclusion is based on factors that were similar to those cited by TGI: an increasingly competitive business environment in which TGI operates, and the fact that all major gas distributors have deferral accounts for the commodity cost of gas and many have rate stabilization or weather protection deferral accounts. In addition, Ms. McShane cites the relatively high concentration of TGI's demand in the industrial sector (40 percent) and the concentration of industrial load in a single industry, pulp and paper (Exhibit B-1, Tab 2, p. 15; T3: 326).

4.2.2 The Intervenors' Response

Dr. Booth disagrees with TGI's assessment of its business risk and submits that there is no significant increase in risk for TGI from higher natural gas costs. Dr. Booth notes that TGI continues to add customers and to grow its customer base, and that Terasen stated in its 2004 Annual Information Form (March 2005) that "Natural gas maintains a competitive advantage in terms of pricing when compared to alternative sources of energy in British Columbia." Dr. Booth also contends that if the risk of residential customers switching to alternative fuels was a significant risk to TGI it would be expected to be tracking and monitoring the situation, and the fact that it does not indicates that this is not considered to be a serious risk (Exhibit C2-6, pp. 32-34).

In Dr. Booth's view, "...utilities have the lowest business risk of just about any sector in the Canadian economy" and notes that the costs and revenues from gas distribution are very stable so that the underlying uncertainty in operating income is very low. Dr. Booth also notes that "...in the event of unanticipated risks, regulated utilities are the **only** group that can go back to their regulator and ask for "after the fact" rate relief" (Exhibit C2-6, p. 28, emphasis in the original).

Dr. Booth addressed TGI's business risk of not earning a return of capital, and offered the following solution:

> "The second and more risky situation is if the company can not rebalance to achieve its revenue requirement. This unlikely situation might occur if industrial and commercial users refuse to pay the higher rates resulting from the loss of residential load. In this case the recovery of the rate base is in question and Terasen runs the risk of stranded assets. However, if this risk is realistic, then the correct response is to change the depreciation rate so that the cost of potentially stranded assets is recovered from the existing users" (Exhibit C2-6, p. 33).

TGI counters this suggestion by citing an excerpt from a NEB decision re TransCanada Pipelines RH-2-2004:

> "…there is a potential that a company's tolls may not incorporate sufficiently high depreciation rates because competitive factors would prevent such rates from being charged. This potential, if significant, is appropriately compensated through the cost of capital.
>
> The assessment of cost of capital should assume that the depreciation rates reflect the best assessment of economic life of the pipeline. Consequently, resetting depreciation rates to reflect a new best estimate of economic life does not, by itself, reduce business risk from what it would be absent a change in the best estimate" (Exhibit B-5, Response to JIESC et al. 7.2c).

The parties do not address the issue further in their Submissions, in the Commission Panel's view, correctly. There is nothing before the Commission Panel to suggest either that the Applicants' depreciation rates do not reflect their best assessment of the economic life of their plant in service; or that their business risks can be eliminated by a change in depreciation rates.

4.2.3 Competitiveness of Natural Gas versus Electricity

With respect to the risks related to the competitive position of natural gas versus electricity, the JIESC notes that TGI had indicated that a year ago it had determined that there was a 95 percent probability that its residential natural gas rates would remain at or below British Columbia Hydro and Power Authority's ("BC Hydro") electricity rates (JIESC Submission, p. 10; T2: 97). However, the Companies submit that this statement refers to its information a year ago and that gas prices have increased since then, further decreasing its competitiveness (T3: 290). The JIESC also notes that TGI's estimate of the competitive electricity price was based on an internal estimate that assumed that electricity prices would increase at approximately one-half the rate of increase of BC Hydro's probable scenario in its 2004/05 Electricity Load forecast (Exhibit C2-15). The JIESC argues that Ms. McShane indicated that gas prices would be expected to moderate somewhat from the current high prices resulting from "the aftermath of the hurricanes" (T3: 330).

The JIESC files a slide from TGI's 2005 Annual Review that shows the five-year forward gas prices at the AECO Hub™ declining from approximately $13.50 Cdn/GJ in January 2006 to $7.00 Cdn/GJ in October 2010 (Exhibit C2-23). This trend is directionally consistent with the opinion of the Companies' witness Ms. McShane (T3: 329-330).

The JIESC also files a page from BC Hydro's December 2004 Electric load forecast for the period 2004/05 to 2024/25. The BC Hydro forecast states that its probable scenario assumes that electricity prices will increase at the rate of inflation (Exhibit C2-15), whereas TGI assumes a rate of increase for electricity prices that was one-half the rate of inflation (T2: 84).

The CEC argues that the risk associated with electric to gas competition has existed since the deregulation of natural gas pricing and as such it is a risk for which the utility has been compensated for a long time. In the view of the CEC, recent competitive pressures reflect supply tightening in the natural gas commodity sector and the realization of underlying risks, which have remained constant (CEC Submission, p. 19). The CEC also notes that Terasen did not use electricity price forecasts available from BC Hydro, nor had it studied the anticipated cost pressures on BC Hydro's electricity rates. The CEC also cites the testimony of Ms. McShane who agreed that a forecast of electric rate increases twice as high as that used by TGI would reduce the competitive pressure (CEC Submission, pp. 20-21).

The CEC disputes Terasen's claim that the customer attachment rate as a percentage of housing starts is approximately one-half of what it was in the mid-1990s (T2: 84). The CEC argues that if one accounts for the lag between the measurement of housing starts and customer attachments the relationship is more constant (CEC Submission, pp. 22-23). The CEC also argues that declining use rates are a normal result of higher efficiency equipment, more use of thermostat controls, increased insulation and trends towards multi-family dwellings. In the view of the CEC, these trends will create lower customer bills and improve the competitiveness of natural gas, even as electricity goes through a similar process of increasing efficiency. The CEC considers the trends concerning TGI to be evidence of "...the consolidation and firming of the core market towards its more fundamental needs..." for natural gas and not a factor increasing risk (CEC Submission, p. 24).

The Companies dispute the CEC argument that accounting for the timing difference between housing starts and customer attachments eliminates the decline, and replies that there has been a significant decline in customer additions and the number of customer additions as a proportion of housing starts since the early 1990s. The Companies also argue that while high efficiency furnaces and other advances may partly explain the decline in use per account, the fact remains that use per account and throughput are decreasing, which will lead to higher unit charges (TGI/TGVI Reply Submissions, p. 16; Exhibit B-12).

The Companies submit that the price competitiveness of natural gas has deteriorated since 1994 and 1999 and that, even though Exhibit C2-23 shows the forward price of natural gas declining over time from current levels, these forward prices continue to be higher than past prices and the Companies will face greater competition from electricity than in the past. The Companies argue that whether or not BC Hydro rates will increase at 1 percent or 2 percent per year is immaterial, when compared to the dramatic change in the relative prices in the price of natural gas and electricity and the volatility of gas prices (TGI/TGVI Reply Submissions, pp. 13-14). The Companies further argue that consumers' purchasing decisions are influenced not only by the absolute level of gas prices but also by their perception of price and volatility (TGI/TGVI Submissions, p. 10).

4.2.4 Deferral Accounts

The Applicants seek no change in their deferral accounts. TGI provides a listing and description of its deferral accounts plus a comparison to Union Gas Limited ("Union"), Enbridge Gas Distribution Inc. ("Enbridge"), Gaz Metro, and ATCO Gas (Exhibit B-3, Appendix 26.5).

TGI maintains two significant commodity deferral accounts: the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA"). These commodity deferral accounts collect the difference between the actual incurred gas costs and recoveries from rates. TGI's non-commodity deferral accounts defer elements of gross margin and of costs. The most significant deferral account for TGI is the Revenue Stabilization Account Mechanism ("RSAM"). The Company describes its operation as follows:

> "The RSAM account deals with the Company's delivery margin and stabilizes the margins recovered from residential and commercial customers. The RSAM stabilizes delivery margin received from these customer classes on a use per customer basis. If customer use rates vary from the forecast levels used to set the rates, whether due to weather variances or other causes, the Company records the delivery charge differences in the RSAM account for refunding or charging through a rate rider to the RSAM rate classes over the ensuing three years. Having an RSAM mechanism does not offer the company protection against forecasting errors due to variances between recorded and forecast number of customers nor does it mitigate any forecasting risks associated with the non-RSAM customer classes such as industrial customers" (Exhibit B-3, Response to BCUC IR1 26.4.1).

TGI states that the approved 2005 delivery margin, including other operating revenues, totals $522.1 million, of which $100.5 million (21.2 percent) is subject to risk without deferral account protection. This amount comprises non-RSAM class customers of $82.4 million (15.8 percent), other operating revenues of $26.0 million (5 percent) and new customer additions of $2.1 million (0.4 percent) (Exhibit B-3, Response to BCUC IR1 26.7).

At December 31, 2004, the unrecovered balance on the RSAM Account was $59.5 million less related tax of $20.5 million (net of $39.0 million). TGI states that the balance on the account has accumulated over 11 years, with the balance being reduced in only two of those years (1996 and 1999).

Cost deferral accounts include the short-term and long-term interest rate deferral accounts which absorb interest rate fluctuations, and pension cost and insurance premiums deferral accounts, the latter two established as part of the 2004-2007 PBR settlement (Exhibit B-3, Appendix 1.5, p. 32). On the expense side, TGI states that of its 2005 test year expenses, O&M expenses of $152.1 million have no deferral protection, along with depreciation of $80.8 million (Exhibit B-5; JIESC IR No. 1, p. 15).

The JIESC argues that the Commission has allowed TGI "some of the most generous risk mitigation measures in the industry through extensive use of deferral accounts and through PBR regulation which provides an opportunity to earn returns above and beyond the allowed return" (JIESC Submission, pp. 11-13).

The CEC also submits that TGI "...has the most attractive deferral account treatment when considering that other jurisdictions are adopting some of these treatments....", and that deferral accounts contribute to providing the Company with very stable and predictable earnings. The CEC states that TGI's concern about deferral accounts is that these are ineffective in dealing with gas on electric competition, and argues that while deferral accounts provide TGI with very stable and predictable earnings, they are not intended to deal with gas on electric competition (CEC Submission, pp. 24-27). The CEC notes that only 18.1 percent of TGI's 2005 Test Year revenue is not covered through deferral accounts and consequently it has a highly predictable accounting income and a highly stable ability to earn its ROE (CEC Submission, pp.17-18; Exhibit B-5, Volume 5, Response to JIESC-BCOAPO-CEC IR1 7.1).

The JIESC notes that TGI earned its allowed return in every year since 1995, with the exception of 1998, which was due to employee severances paid out as a result of a major corporate restructuring to take advantage of PBR (JIESC Submission, p. 17; Exhibit B-5, JIESC-BCOAPO-CEC IR 7.1; T2: 79). The BCOAPO and the CEC echo this argument (BCOAPO Submission, p. 9; CEC Submission, p. 12).

The Companies agree with the CEC's submission that deferral accounts cannot deal with gas on electric competition and have not been proposed for such a purpose. The Companies also note that Dr. Booth indicated that the RSAM account should not affect the return on equity allowed (TGI/TGVI Reply Submissions, pp. 17-18).

The Companies acknowledge that PBR is beneficial to shareholders, but argue that it takes on additional risk by committing to O&M and capital targets, and by limiting its ability to seek relief from the Commission (T3: 286; TGI/TGVI Reply Submissions, p. 12).

4.2.5 The Companies' Response to Risk

The JIESC points to the TI annual report and testimony regarding the annual report to argue that:

> "The failure of Terasen to disclose any new material competitive risks in its annual report, where they must be disclosed or there will be legal penalties, should be proof that there are no new material risks the shareholders, or for that matter, there are no new material risks that the Commission should be concerned about" (JIESC Submission, p. 15).

In the JIESC's view there is no evidence that any prudently acquired asset of TGI will be economically stranded or that it will be unable to earn its allowed ROE in the future as it has in the past (JIESC Submission, p. 9).

The CEC also argues that if the risks to TGI were substantive, one would expect it to have invested in studying those risks and to have disclosed them in their Annual Report and Prospectuses where there is a legal obligation to disclose and be truthful. The CEC submits that the TI Annual Report and Prospectuses contain scant, if any, discussion of risks or disclosure of the potential to switch to alternative fuels. The CEC further argues that TGI appears not to have done any serious analysis to study or demonstrate the validity of the risk related to the price of gas relative to electricity, nor of consumer behaviour that would enable it to cope with competitive risks if they were significant (CEC Submission, pp. 32-36).

The CEC further submits that TGI has neglected to take actions that could mitigate the risks it perceives and has undertaken actions that exacerbate the problems it cites, including investment in expensive or uneconomic projects. The CEC also argues that TGI proceeded to acquire TGVI in spite of risks that were present before TGI purchased the utility. In summary, the CEC argues that TGI's response to its perceived risk is "tepid and weak" and consequently should not be granted any increased ROE or equity component at this time (CEC Submission, pp. 30-39).

The CEC dismisses TGI's claims with respect to various other risk adjustment factors, such as gas supply management challenges, cost management issues, regulatory accounting risks, and lack of growth. The CEC argues that TGI's claims with respect to these risks are either self-contradictory or unsupported by the evidence. The CEC submits that the underlying risk differs from the realized outcomes associated with risk and that the realization of a risk that has existed for some time does not change the risk of a company (CEC Submission, pp. 28-29).

The Companies contend that the risk disclosure in the TI Annual Report is appropriate in the context of Terasen Inc. and that an exhaustive discussion of TGI and TGVI's business risks comparable to the discussion in the hearing would give investors a distorted view of the overall business risk of Terasen Inc. "...given that its business risk remains relatively low compared to the broad equity market" (TGI/TGVI Reply Submissions, p. 11).

The Companies acknowledge that TGI is less risky than the "average" company (quotation marks in original) but argues that the evidence demonstrates that the relative risks of both TGI and TGVI have increased and that the risks faced by the Companies are greater than those faced by most other gas utilities in Canada (TGI/TGVI Reply Submissions, p. 10).

Commission Determinations

The Commission Panel finds that the vast majority of gas distribution companies in North America have some form of commodity deferral account, and that this protects both the utility from commodity risk and the customers from imprudent purchasing and from the utilities profiting from the purchase, transportation and storage of gas.

With the exception of the RSAM, which is discussed below, the Commission Panel finds that many of the other costs which are deferred by TGI are deferred as a result of PBR so that TGI is not penalized for underestimating or rewarded for overestimating a cost over which it has little or no control. Thus, the deferral is symmetrical. The Commission Panel finds the RSAM to be a unique account. It has two facets that the Commission Panel will consider separately.

The RSAM acts as a weather normalization account. In this regard, TGI is similar to a number of utilities in North America (including Gaz Metro and Newfoundland Power Inc., in Canada) that can defer the effects of temperature when and where it differs from a long-term norm used to set rates. The Commission Panel agrees with Dr. Booth and Ms. McShane that weather is a symmetrical risk, with equal odds of over and underachieving, that should not be taken into account when establishing the ROE for a benchmark low-risk utility.

The second function of the RSAM is to enable TGI to defer margin variances arising from residential and commercial customers consuming more or less gas than forecast. The Commission Panel considers this aspect of the RSAM to be a short-term business risk mitigant, which is not available to TGI's comparators. By "short-term", the Commission Panel means that it agrees with the Applicants that "the RSAM does not provide for recovery of the return on, or of, capital in the longer-term."

The issue is "whether the Applicants' business risk has increased," that is to say has the probability of TGI not earning a return on and of its capital increased since 1994. The evidence before the Commission Panel is clear: TGI has consistently achieved its allowed ROE in all years except one. The Commission Panel views the AAM, PBR and the RSAM as mechanisms that act to reduce the risk that TGI will not earn a return on its capital. As to earning a return of its capital, that is to say will TGI be able to recover its investment in property and plant in service through rates for service collected from its customers, the evidence is not as clear. In 1994, the evidence before this Commission was of a utility whose product enjoyed a broad competitive edge over electricity, whose long-term supply at reasonable prices seemed assured, and which was able to capture a significant share of new residential market. As Dr. Booth observed "So what happens is the growth allows more customers to lower the unit costs on the system, thereby making the distribution charge slightly lower making it slightly more competitive" (T5: 673). Today, TGI's competitive advantage has been significantly attenuated; its supply outlook has been altered by shippers moving B.C. gas east; and its capture rates in the new residential market have declined.

The Commission Panel can say with certainty that TGI's business risk has not declined in the period 1994-2005. It cannot say by how much its business risk increased, but it can say that although the probability of TGI not earning a return of its capital has increased, it continues to be very low.

The Commission Panel also shares the CEC's observation that if TGI genuinely perceives that it is facing increasing risk, it has a responsibility to undertake cost-effective actions that will mitigate risk. Such actions could include monitoring customer behaviour more closely in terms of such issues as fuel switching, disconnections, and energy efficiency and increasing efforts to offset the customer perception, cited by TGI, that natural gas is an expensive fuel.

4.3 TGVI

4.3.1 Evidence and Argument

In addition to the risks faced by TGI, the Companies set out the following risks peculiar to TGVI:

1) Building a new market on Vancouver Island;

   Ms. McShane describes TGVI as a relatively small greenfield utility, its market being built from the ground up over the past 15 years. TGVI's rates have been structured to compete with alternative energy sources and to induce potential customers to convert to natural gas. Ms. McShane summarizes that until 2003 TGVI's rates were set at a discount to competing fuels, too low to recover TGVI's cost of service and resulting in accumulations to the Revenue Deficiency Deferral Account ("RDDA"). Since 2003 TGVI's rates have been based on a cost of service model, incorporating a soft cap mechanism to maintain the competitiveness of rates in the residential and commercial sectors relative to electricity or oil alternatives (Exhibit B-1, Tab 2, pp. 18-19).

2) Continuing recovery of the RDDA:

   The Companies state that BC Hydro revenues from firm transportation of natural gas to the Island Cogeneration Project ("ICP"), in conjunction with royalty payments pursuant to the VINGPA, have allowed TGVI to reduce the RDDA to approximately $60 million at December 2004 from its peak at $88 million in 2002.

   The Companies argue that while TGVI and BC Hydro have signed a two-year transportation service agreement for the firm transportation of natural gas to ICP, there is no commitment from BC Hydro as to what will happen after the expiry of that contract. The Companies are concerned about the uncertainty of recovering roughly $16 million of the RDDA balance from BC Hydro in 2008 (TGI/TGVI Submissions, p. 19). The Companies summarize that under the approved 2006-2007 negotiated settlement agreement the RDDA balance is expected to be reduced by approximately $17.4 from a total of $52 million as of December 31, 2005 (TGI/TGVI Submissions, p. 20), or to roughly $34.6 million by the end of 2007 (Exhibit A3-6, Appendix A, Schedule 1, p. 14).

3) Planning for the elimination of Provincial royalty revenues in 2012 covering approximately 20 percent of the current cost of service;

   The Companies summarize that under VINGPA, TGVI receives royalty payments from the Provincial Government that reduce the cost of the gas commodity, which, in turn, improves the margin available to recover delivery costs. The Companies state that after the payments terminate at the end of 2011, TGVI's customers will be required to absorb the full commodity cost of gas. The Companies contend that the ability of TGVI to mitigate the impact of rising costs on customer rates will partly depend on its ability to add new customers, which hinges in large part on the competitiveness of TGVI's rates versus electricity rates. The Companies submit that given the intensely competitive market in which TGVI operates, there is a material risk that it will be unable to recover its full investment in utility assets (Exhibit B-1, Tab 2, p. 19).

   The Companies expect that the annual royalty payments will have grown to $60 million by 2012. The Companies submit that if TGVI has to apply for a $60 million revenue requirement increase in 2012 it would result in a rate increase of 35 to 40 percent across all customer classes, and that the current mechanism does not provide an adequate level of return to compensate for this risk (TGI/TGVI Submissions, p. 20).

4) High dependence on industrial load, in excess of 65 percent of throughput, two thirds of which is contracted on a year to year basis. The Companies note that 66 percent of TGVI's load and 38 percent of its margin is industrial, comprising of the ICP and seven pulp mills.

5) Security of supply risk since all gas to the Island flows from a single source on the mainland and is also dependent on the use of undersea high pressure transmission facilities. Ms. McShane describes TGVI as facing greater supply risks than the typical distribution utility, due to its dependence on a single pipeline system that traverses rugged terrain, with underwater and marine crossings (Exhibit B-1, Tab 2, p. 19).

6) Future repayment of $75 million non-interest-bearing senior government debt, currently sitting (sic) as a credit to rate base. The Companies point out that repayment will increase TGVI's rate base, contribute to higher cost of service and impact TGVI's competitive position (Exhibit B-1, Cover letter, p. 12).

The Applicants testify that, after the filing of the Application on June 20, 2005, BC Hydro has advised that it is evaluating the operation of the ICP as a peaking unit and purchasing transmission on an interruptible basis. As a consequence of this advice, TGVI states that it has elected not to proceed with its plan to sell a long-term bond issue to Canadian institutions and has chosen to refinance its debt in the amount of $350 million with short-term bank debt. This event has also caused its plan to obtain a rating for its long-term debt to be put on hold (T3: 316).

4.3.2 TGVI Deferral Accounts

A comparison of TGVI and TGI's deferral accounts to other Canadian gas utilities was provided (Exhibit B-3, Appendix 1.5). TGVI maintains a commodity deferral account called the Gas Cost Variance Account that captures the difference between actual and approved cost of gas. TGVI's most significant non-commodity deferral account is the RDDA, which has been operating for 15 years (Exhibit B-1, Tab 2, p. 18).

TGVI states that its approved 2005 delivery margin, including other operating revenues, is $118.0 million. Of this amount, $18.0 million of forecast revenue surplus is at risk without deferral account protection. The $18.0 million equates to 15.3 percent of TGVI's delivery margin.

TGVI states that the Special Direction provides for TGVI to have a RDDA funded by its shareholder. The RDDA shareholder funding mechanism has the result that in years when the revenues of TGVI are insufficient for it to earn its allowed return the shareholder funds the shortfall to cause the utility to have sufficient revenues to earn its return and vice versa (TGI/TGVI Submissions, pp. 19-20).

TGVI claims that its RDDA provides apparent protection against revenue risk, but it only does so through the shareholder funding the revenue deficiencies. Therefore, in reality, all revenues are at shareholder risk. It expects that in the longer term, if and when the RDDA balance is reduced to zero, a mechanism similar to TGI's RSAM will be put in place. The risk for TGVI is not so much delivery margins risk, but rather credit collection risk and whether its rates can ever be competitive, particularly after royalty revenues cease after 2011 (Exhibit B-3, p. 88).

Schedule 1 in TGVI's Negotiated Settlement Agreement for the 2006-2007 Revenue Requirements on line 28 (Exhibit A3-6), shows that in 2002 the RDDA reached a peak accumulated deficit of $88 million. From 2003 to 2004 TGVI has realized annual surpluses (Exhibit B-16, lines 41-42). These surpluses are expected to continue through to the end of 2007 resulting in a forecast RDDA balance of $34.7 million. Since 2003, TGVI's "soft-cap" rate design mechanism, together with revenues from the transportation agreement with BC Hydro, have allowed TGVI to incur annual surpluses. These surpluses allow TGVI to pay down the accumulated shareholder funded deficits and thus reduce the RDDA balance.

The RDDA allows TGVI to earn its allowed ROE before the VINGPA provision of $1.9 million and (Exhibit B-16, lines 1-10, col. a) which was a component in the Special Direction and agreed to in the VINGPA agreement in a negotiated arrangement (T3: 250). In a deficit year the RDDA revenue deficiency is added to earnings before revenue deficiency and in a surplus year the RDDA revenue surplus is subtracted from earnings before revenue deficiency in order to calculate net earnings (Exhibit B-16, lines 41-49, col. b).

The JIESC argues that some of the risks cited by TGVI, particularly the accumulation of a deficit that peaked at approximately $88 million in 2002, but has since been reduced approximately to $53 million in 2006 and $40 million in 2007, the planning for the elimination of the provincial royalty revenues in 2012, and the recent reductions in industrial gas throughput, could be a concern if they are taken out of context. The JIESC submits that while considering these concerns one should remember:

- That BC Hydro believes electricity rates will probably increase at the rate of inflation;
- That natural gas prices will probably decrease from current record levels; and
- That the combination of the two previous factors should make dealing with adverse factors much easier than anticipated by the Companies in the TGVI evidence (JIESC Submission, pp. 20-21).

The JIESC argues that the risks to TGVI are not new risks, but part of this project since its inception, and assumed by Terasen Inc. voluntarily when it purchased TGVI in March 2002. The JIESC stresses that in January 2003, TGVI voluntarily accepted a capital structure of 35 percent and a return on equity 50 basis points above the allowed return on equity of the benchmark utility as part of the 2003-2005 settlement agreement, and that there is no good reason to change either now. Further, the JIESC contends that the increased risks cited by TGVI are simply too remote to warrant any change in the capital structure or the return on equity of TGVI, particularly when upside opportunities are considered along with risk. The JIESC submits that both the allowed ROE and the capital structure should remain at present levels (JIESC Submission, p. 21). It also argues that to increase these components would make the utility less competitive and would affect recovery of the RDDA (JIESC Submission, p. 24).

The CEC argues that TGI proceeded with the acquisition of TGVI knowing the risks that TGVI faced and that the Commission cannot hope to deal with these risks through increasing equity and return on equity (CEC Submission, p. 38). The CEC contends that a utility that is now facing the realization of a risk for which it has been and continues to be compensated should not have access to even greater returns and even greater investment levels when the risks are being realized (CEC Submission, p. 29). The CEC also submits that TGI should work with the Provincial Government and its customers to develop long term plans for dealing with the pending materialization of risk that TGVI faces (CEC Submission, p. 45).

The Companies submit that the JIESC's statement that the TGVI risks are not new risks ignores the evidence that there has been a marked change in the risks of TGVI. While the JIESC says that risks are simply too remote, particularly when upside opportunities are considered along with risks, the Companies submit that the

Commission should not wait until an event occurs before recognizing the potential for that event to be a risk faced by a utility. The Companies contend that there is nothing remote about the loss of industrial demand, or high gas prices, or the loss of Royalty Revenues at the end of 2011 (TGI/TGVI Reply Submissions, p. 24).

The Companies argue that CEC's suggestion that TGI [sic] work with the Provincial Government and its customers recognizes that TGVI has significant risk that is materializing. The Companies submit that there is an obligation on the Commission to consider and determine those risks at this time; the Commission cannot avoid its obligations by referring TGVI's problems to the Provincial Government (TGI/TGVI Reply Submissions, pp. 30-31).

Commission Determinations

Section 3.1 of this decision deals directly with the TGI's business risks, and the Commission Panel attributes the same determinations to the change in the similar components ascribed to TGVI's business risk. The following determinations deal only with those TGVI risks summarized at the beginning of this section.

In assessing the business risk of TGVI, the Commission Panel is cognizant of the standard it set above when it defined business risk as the ability to earn a return on and of capital.

The Commission Panel finds that the uncertainty surrounding the contract with BC Hydro beyond 2007 creates a significant incremental change to TGVI's business risk together with uncertainty as to the ultimate recovery of the balance on the RDDA. In addition, the uncertainty regarding the cessation of royalty payments from the Provincial Government and the need to repay the interest free loans from senior levels of government demonstrate that TGVI is exposed to considerably greater business risk than a benchmark low-risk utility. It is evident to the Commission Panel that in TGVI's case the probability of not earning a return on and of capital is considerably higher than is the case with the five "mature" gas distribution companies in Canada.

5.0 CAPITAL STRUCTURE

This section considers the appropriate capital structures for TGI and TGVI.

Dr. Booth believes the Commission should adjust for changes in business risk through the establishment of deferral accounts, as far as is practicable, then to alter the amount of debt financing; and then to alter the allowed ROE (Exhibit C2-6, p. 24). A review of deferral accounts is outside the scope of this proceeding. Therefore, determinations in this decision with respect to capital structure and returns on equity assume the deferral accounts are not changed. Further, the Commission Panel has used both capital structure and rates of return for establishing the appropriate financial profile for the Applicants. In this decision, the capital structure of TGI will be determined so as to equate TGI to the benchmark low-risk utility. In the case of TGVI, the reasonableness of the proposed capital structure and equity premium off of the return on equity for the benchmark low risk utility will be considered.

The capital structures of other B.C. utilities are outside the scope of this proceeding, although the approved capital structures of other B.C. utilities are considered relevant to the determination of an appropriate capital structure for TGI and TGVI.

5.1 TGI

The Applicants apply for a 38 percent common equity ratio for TGI.

5.1.1 Capital Structures of Other Canadian Gas Distribution Utilities

The table below provides the capital structures of other Canadian Gas Distribution Utilities:

Tab 2
SCHEDULE 5
PAGE 1 of 3

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR INVESTOR-OWNED CANADIAN UTILITIES
(Percentages)

	Decision Date (1)	Order/ File Number (2)	Debt (3)	Preferred Stock (4)	Common Stock Equity (5)		Equity Return (6)	Forecast 30-Year Bond Yield (7)	
Electric Utilities									
AltaLink	11/04	EUB 2004-423	65.00	0.00	35.00	a/	9.50	5.55	
ATCO Electric									
Transmission	11/04	EUB 2004-423	61.00	6.00	33.00		9.50	5.55	
Distribution	11/04	EUB 2004-423	56.10	6.90	37.00		9.50	5.55	
FortisAlberta Inc.	11/04	EUB 2004-423	63.00	0.00	37.00		9.50	5.55	
FortisBC Inc.	11/04; 5/05	L-55-04; G-52-5	60.00	0.00	40.00		9.43	5.53	
Newfoundland Power	12/04	PU 50 (2004)	54.06	1.39	44.55		9.24	4.96	
Nova Scotia Power	3/05	NSUARB-NSPI-P-881	53.30	9.20	37.50		9.55	na	b/
Gas Distributors									
ATCO Gas	11/04	EUB 2004-423	55.10	6.90	38.00		9.50	5.55	
Enbridge Gas Distribution Inc	1/04;12/04	RP-2002-0158; RP-2003-0203	61.91	3.09	35.00		9.57	5.81	
Gaz Metropolitain	9/04	D-2004-196	54.00	7.50	38.50		9.69	5.80	c/
Pacific Northern Gas	11/03; 7/04	L-57-03; G-69-04	60.32	3.69	36.00		9.80	5.65	d/
Terasen Gas	11/04	L-55-04	67.00	0.00	33.00		9.03	5.53	
Union Gas	1/04;3/04	RP-2002-0158; RP-2003-0063	61.50	3.50	35.00		9.62	5.68	
Gas Pipelines									
Alberta Natural Gas	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
Foothills Pipe Lines (Yukon) Ltd.	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
TransCanada PipeLines	11/04; 4/05	RH-3-94/RH-2-2004	64.00	0.00	36.00		9.46	5.55	
Trans Quebec & Maritimes Pipeline	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
Westcoast Energy	8/04; 11/04	RH-2-94; RH-1-2004	69.00	0.00	31.00		9.46	5.55	

a/ EUB 2004-052 set the equity ratio at 35% (33% for transmission plus 2% in recognition of AltaLink's tax status).
b/ The Board approved an ROE of 9.55% for ratemaking purposes and set the earnings range at 9.30-9.80%.
c/ Gaz Metro is allowed to earn an additional 1.95% based on expected productivity gains for the 2005 fiscal year.
d/ 2005 rate application currently pending.

Source: Board Decisions.

Source: Exhibit B-1, Tab 2, Schedule 5, p. 1

As indicated in the above table, all the other major gas distribution utilities have preferred shares in their capital structures. Since 1994 the allowed common equity of TGI has been 33 percent. In 1999 preferred shares were redeemed that accounted for 9.4 percent of the capital structure. The preferred shares of ATCO Gas, Enbridge, and Union are perpetual preferred shares. The Commission Panel accepts the evidence of TGI that it does not have a credit rating high enough to enable it to issue perpetual preferred shares (T3: 267). Therefore, the Commission Panel concludes that the preferred shares of ATCO Gas, Enbridge and Union need to be considered when comparing the capital structures of those utilities with TGI.

Ms. McShane and Dr. Booth reach similar conclusions regarding the relative risk of Canadian utilities. Ms. McShane's view is that TGI's business risks are comparable to those of the major Alberta and Ontario distributors, and exceed those of electric transmission companies by a considerable margin (Exhibit B-1, Tab 2, p. 16). Dr. Booth is also of the view that electric transmission companies have a lower risk than TGI, and are judged to be the lowest risk regulated utilities in Canada. The AEUB has found that appropriate capital structure for electric transmission companies with no preferred shares is 33 percent.

McShane is of the view that TransCanada Pipelines and Nova Gas Transmission face no higher business risk than TGI. Dr. Booth is of the view that the gas transmission pipelines are the second lowest risk group. The allowed common equity ratio for TransCanada Pipelines, Mainline and Nova Gas Transmission are 36 percent and 35 percent respectively.

Dr. Booth then judged the local distribution companies, including both gas and electric as the next riskiest. Ms. McShane is of the view that TGI's business risks are comparable to those of the major Alberta and Ontario gas distributors. The allowed common equity ratios for the Ontario major gas distributors are in the range of 35 percent and the allowed common equity ratios for the Alberta gas distributors are higher at 38 percent.

In testimony, Dr. Booth indicated that TGI is riskier than ATCO Gas and Enbridge, roughly on par with Union, while being less risky than Gaz Metro (T5: 619-620). Dr. Booth views PNG and Gaz Metro as the riskiest regulated utilities in Canada (Exhibit C2-6, p. 36).

Although Dr. Booth recommends 35 percent for a typical local gas distribution company, he recommends 33 percent for TGI because of more comprehensive deferral accounts. The Commission Panel accepts that the TGI's earnings are less volatile than the earnings of Enbridge and Union, and such reduced volatility can be attributed, in part, to weather normalization. The Commission Panel also notes Dr. Booth's testimony that "I think they (sc Enbridge and Union) are probably happier not having weather normalization. Otherwise they would have proposed it" (T5: 639). The Applicant submits that the existence of the RSAM account is not a factor that should play a role in the determination of its allowed return on equity or its capital structure. Dr. Booth confirmed in his opening statement that weather risk should not affect the return on equity (TGI/TGVI Submissions, p. 14, para. 46 and 47).

5.1.2 Coverage Ratios and Credit Ratings

The pre-tax interest coverage ratios for the major gas distribution companies in Canada are set out below:

PRE-TAX INTEREST COVERAGE RATIOS
FOR MAJOR CANADIAN UTILITIES

Company	1995	1996	1997	1998	1999	2000	2001	2002	2003
Enbridge Gas Distribution	2.0	2.6	2.6	2.1	2.2	2.2	2.8	2.7	2.7
Gaz Metro	2.6	2.6	2.7	2.7	2.4	2.7	2.5	2.9	2.9
Pacific Northern Gas	2.1	2.7	2.6	2.3	2.3	2.3	2.3	2.5	2.3
Terasen Gas	1.8	2.0	2.3	2.3	2.3	1.9	1.8	2.0	2.0
Union Gas	2.2	2.3	2.4	2.0	1.8	2.0	1.9	2.1	2.1

Source DBRS (Exhibit B-1, Tab 2, Schedule 2)

TGI's interest coverage ratio for 2004 was 1.99 (Exhibit B-28)

TGI's Medium Term Note ratings for the years 1994, 1999 and 2004 are set out below:

Rating Agencies	**1994**	**1999**	**2004**
DBRS	A	A	A
Moody's	-	-	A2
CBRS/S&Ps	B++	A (low)	BBB (unsolicited)

Source: Exhibit B-3, Vol. 1, Appendix 2.1

On June 26, 2003, Standard & Poors downgraded TGI's rating from BBB+ to BBB. In the first quarter of 2004 TGI terminated Standard & Poors' engagement to provide credit ratings in order to manage costs. However, S&P elected to continue to publish unsolicited credit ratings on TGI debt. On December 19, 2005, Moody's lowered TGI's senior secured rating from A1 to A2 and TGI's senior unsecured rating from A2 to A3 (Exhibit B-27). Both Moody's and S&P are of the view that the low common equity component in the capital structure of TGI results in a weak financial profile. TGI submits that the December 2005 downgrading demonstrates the need for an increase to the common equity and return on equity for TGI (TGI/TGVI Reply Submissions, p. 27).

In its credit rating report on TGI dated June 22, 2004, DBRS makes the following comments on TGI from a credit analyst's (and thus bondholder's) perspective:

> "The company benefits from a supportive regulatory regime,"
>
> "The regulatory environment within which the company operates provides a relatively high degree of financial stability."
>
> "Key financial ratios are expected to continue to fluctuate within a narrow band in line with changes in working capital requirements, however, this does not pose any credit implications."
>
> "Terasen Gas has historically had the lowest allowed ROEs relative to all other gas distribution utilities in Canada. This has resulted in generally weaker financial ratios relative to its Canadian peers," and
>
> "The use of the taxes payable method of taxation (typical of rate-regulated utilities) has resulted in an unrecorded future income tax liability of $215.8 million as at December 2004. The recovery of this liability in future rates depends on regulation" (Exhibit B-5, Appendix 1.2).

The Commission Panel notes these comments by DBRS. First, the interest coverage ratios are stable and are unlikely to pose any credit implications in the future. Second, the lowest allowed returns, when combined with the lowest equity component relative to all other gas distribution utilities in Canada, have resulted in the lowest interest coverage ratios in Canada.

The Commission Panel accepts that if TGI is downgraded by one of the rating agencies to a non-investment credit that it could limit the number of investors willing to hold TGI debt securities. For that reason, investors may be reluctant to hold debt that is just one notch above BBB-. A credit rating below an S&P BBB- is considered "junk" (T3: 263-265). Therefore, TGI's credit rating would fall to non-investment grade (junk) status if S&P downgrades TGI by only two notches. In the December 19 Announcement, Moody's states:

> "TGI's rating considers the support provided by TGI's regulatory environment which limits TGI's exposure to commodity price and volume risks as well as pension funding costs and insurance costs by operation of numerous deferral mechanisms including Commodity Cost Reconciliation Account (CCRA), Midstream Cost Reconciliation Account (CCRA) and the Revenue Stabilization Adjustment Mechanism (RSAM). However, the rating also recognizes that the deemed equity and allowed ROE permitted by the regulator are among the lowest in Canada which contributes to TGI's weak financial metrics relative to its global peers" (Exhibit B-27).

The Applicants submit that TGI's hedging agreements require that collateral be posted if its rating falls to non-investment grade, which could trigger significant and sudden liquidity requirements. TGI's gas purchase agreements require that collateral be posted if the counterparty has reasonable grounds for insecurity, which could be triggered by a downgrade to non-investment grade (TGI/TGVI Submissions, p. 25, para. 85; T3: 265).

Dr. Booth believes that because bond rating agencies are concerned with accurately predicting the credit quality of a firm's debt, they take a conservative approach because of "asymmetry of risk" and sometimes over react (Exhibit C2-6, pp. 76-77). Moreover, Dr. Booth submits that S&P's decision to impose harsher credit standards has had no impact on spreads or presumably marketability of future debt issues, and notes that spreads have almost all declined since end of 2002 (Exhibit C2-6, p. 78). During the Oral Phase of Argument, TGI advised that there has been no determinable change in the market following the Moody's downgrade (T7: 984). The JIESC submits that the ratings are the agency's view of the utility, and that a more important view is the markets view as evidenced by the spreads.

The spreads of TGI with comparators including Enbridge and Union are provided at Exhibit C2-11, Exhibit C2-11 and BCUC IR No. 1, 32.1.1.2. TGI's 30-year bonds trade at spreads that are approximately 15-20 basis points higher than Enbridge and at spreads that are similar to Union's. In Reply Argument, TGI submits that TGI bonds trade at approximately 30 basis points higher than Enbridge; however, the trade spreads indicated on BCUC IR No. 1, 32.1.1.2 are 20 basis points and the estimated spreads for a new 30 year issue are approximately 30 basis points. TGI then submits that the "30 basis point spread" reflects a "particularly accommodating point in the interest cycle for TGI bonds" (TGI/TGVI Reply Submissions, p. 20).

Dr. Booth's view is that the S&P and the Moody's ratings for Terasen are out of line with what the market feels is the correct rating. During the Oral Phase of Argument, the JIESC also notes that both the Moody's and DBRS ratings are "A" ratings (T7: 978).

The Commission Panel also notes the submissions of TGI that from the perspective of independent parties, who can see there has been a change, the downgrades suggest the business risks and the financial risks of TGI have increased (T7: 980).

5.1.3 Access to Capital Markets and Financing Flexibility

The JIESC observes that TGI was able to raise 30 year debt in 2005 on reasonable terms. The Applicant's Treasurer Mr. Bryson states:

> "I think the point that I want to leave on this is that obviously one of the key standards that a fair return on equity and capital structure has to meet is the ability to raise financing even in adverse conditions. And I think that was acknowledged by this Commission in the 1999 ROE decision. And what I'd like to submit is that the ability to issue 30-year bonds once every five or ten years does not provide evidence that that test is being met" (T2: 154).

Mr. Bryson states that in 2005 at least seven BBB rated companies were able to issue 30 year debt (T2: 127).

The Commission Panel accepts the need for a utility to be able to access capital markets under most circumstances at reasonable rates.

Commission Determinations

The Commission Panel concludes that the appropriate capital structure range for consideration of TGI is in the range of 35 percent to 38 percent and that given the effect of deferral accounts in reducing the risk of TGI, the appropriate equity component for TGI is 35 percent. Given the preferred shares in the capital structure of all other Canadian gas distribution utilities, the equity component of TGI will remain the lowest in Canada for gas distribution utilities.

While the Commission Panel accepts the submissions of the JIESC that since utilities have the lowest business risk of just about any sector they should have the highest debt ratios, it nevertheless concludes that an increase to the capital structure of TGI is supported by post-1994 changes to the capital structure of TGI and by comparisons to the approved capital structures of comparable risk utilities. Credit rating downgrades by S&P and Moody's are relevant and also support a need for a change to the capital structure.

The Commission Panel requires TGI to file within 30 days of this decision a document setting out how and when it will implement this change to its capital structure in compliance with the ring-fencing conditions approved by the Commission on page 49 of the KMI Decision.

5.2 TGVI

The Applicants apply for a 40 percent common equity ratio for TGVI.

TGVI is also in an increasingly competitive environment. Ms. McShane says that TGVI faces higher risk than any of the major mature gas distribution utilities, and is more comparable to the smaller mature utilities and the greenfield gas distributors in the Maritimes (Exhibit B-1, p. 20). In particular, Ms. McShane views TGVI to be somewhat less risky than either of Enbridge Gas New Bruswick or Heritage Gas and to be in the same business risk class as Gazifiere Inc. and Natural Resource Gas. Ms. McShane also views TGVI to have higher business risk than FortisBC (Exhibit B-3, Vol. 2, IR 1.45.3). Ms. McShane provides the allowed common equity ratios of these utilities, which have a range from 40 percent to 50 percent and recommends a common equity range for TGVI of 45-50 percent.

The business circumstances of TGVI have changed since Ms. McShane's evidence was filed. TGVI has not sought a thicker common equity ratio or a higher return on equity as a result of the new circumstances, but submits that the circumstances have changed the business risks and provide further evidence of the reasonableness of the capital structure and return on equity that is being sought by TGVI.

The Applicants note that TGVI has the same allowed common equity as Enbridge, has no preferred shares, and is allowed approximately the same level of equity as Enbridge. Further, that the risk profiles of TGVI and Enbridge are not remotely similar (TGI/TGVI Submissions, p. 32).

Dr. Booth did not file evidence related to TGVI. The JIESC submits that there is no justification for changing the capital structure of TGVI at this time and that it does not make sense to do so.

Commission Determinations

The Commission Panel concludes that the appropriate common equity component in the capital structure of TGVI is 40 percent.

The Commission Panel requires TGVI to file within 30 days of this decision a document setting out how and when it will implement this change to its capital structure in compliance with the ring-fencing conditions approved by the Commission on page 49 of the KMI Decision.

6.0 RETURN ON EQUITY

6.1 The Applicants' Methodology

This Section considers the appropriate return on equity for a benchmark low-risk utility, and applies its determination in that regard to the return on equity for TGI and TGVI.

The Applicants introduce the evidence of Kathleen McShane (Exhibit B-1, Tab 2). Ms. McShane says that a fair return is one that provides a utility with the opportunity to:

1. earn a return on investment commensurate with that of comparable risk enterprises;
2. maintain its financial integrity; and,
3. attract capital on reasonable terms.

According to Ms. McShane these criteria give rise to two separate standards, the capital attraction standard and the comparable returns, or comparable earnings, standard. Ms. McShane states that the two standards require the use of three tests used to develop her recommended fair return on equity for a benchmark low-risk utility:

- *Equity Risk Premium (ERP)* test, which is a generic term for a methodology that estimates the cost of equity as the sum of a directly observable yield on a security such as a government or corporate bond and a premium to compensate for the additional equity risk assumed by the investor;

- *Discounted Cash Flow (DCF)* test, which measures the equity investors' expected return as the dividend yield on a stock or group of stocks plus the expected growth in dividends in the long term; and

- *Comparable Earnings (CE)* test, which measures the experienced returns on book equity of firms that are of similar risk to the utility for which the regulator is setting the fair return (Exhibit B-1, Tab 2, lines 720-734).

6.1.1 <u>ERP Test</u>

Ms. McShane uses three methodologies to derive her equity risk premium as follows:

- Risk-Adjusted Equity Market
- Historic Utility
- DCF based

<u>Risk-Adjusted Equity Market</u>

Ms. McShane uses the period 1947-2004 to examine the average risk premium experienced in the Canadian, US and UK markets as follows (Exhibit B-1, Tab 2, Schedule 8):

	Stock Return	**Bond Return**	**Risk Premium**
Canada	12.1	6.9	5.3
United States	13.2	6.3	7.0
United Kingdom	14.9	8.9	6.0

Ms. McShane uses the arithmetic average that is the sum of each year's return divided by the number of years in the study. Ms. McShane addresses the issue of high bond returns in recent years by substituting her estimate of current long bond yields (5.25 percent) rather than historic average returns. From this she develops an indicated Canadian equity market risk of 6.75 percent, being the mid-point of a range of 6.25 percent to 7.25 percent. Ms. McShane applies a relative risk adjustment factor (beta) of 0.65, which she derives by developing "raw" betas from Canadian data which exclude Nortel. She then adjusts her "raw" beta using a formula used by major commercial suppliers of betas, which gives two-thirds weight to a stock's own beta and one-third weight to the market mean beta of 1.0. Thus, she arrives at a benchmark utility equity risk premium of 4.0 percent (Exhibit B-1, Tab 2, lines 1577-1968).

<u>Historic Utility Equity Risk Premium</u>

In Schedule 16 of her evidence, Ms. McShane observes actual utility equity (arithmetic average) risk premiums as follows:

1956-2004	Canada – gas and electric	4.4%
1947-2004	US – gas	6.0%
1947-2004	US – electric	5.0%

From which she determines that an appropriate historic utility equity risk premium for a benchmark low-risk utility to be in the range of 4.25-5.0 percent or approximately 4.75 percent (Exhibit B-1, Tab 2: lines 1985-2000).

DCF-Based Equity Risk Premium Test

Ms. McShane compares the estimated DCF cost of equity of seven US gas utilities over the corresponding 30-year U.S. Treasury yield on a monthly basis for the years 1993-2004 (Exhibit B-1, Tab 2, Schedule 18). This test indicates an average risk premium over the period of 4.2 percent. Since the corresponding bond return is 6.0 percent, Ms. McShane increases the observed premium to 4.7 percent to reflect her forecast yield on a 30-year (Canadian) government bond of 5.25 percent. At the same time, she tests the relationship between the spreads between U.S. long-term A-rated utility and 30-year U.S. Treasury yields and determines a utility risk premium of 4.3 percent. Ms. McShane settles on a mid-point of 4.5 percent for her DCF-based ERP test (Exhibit B-1, Tab 2, line 2140).

Financing Flexibility Allowance

To each of the three risk premiums developed by her tests, Ms. McShane adds a Financing Flexibility Allowance of 50 basis points. This allowance is intended to cover three aspects:

- flotation costs;
- a cushion for unanticipated capital market conditions; and
- a recognition of the fairness principle.

Ms. McShane's ERP test results are summarized as below (Exhibit B-1, Tab 2, p. 83):

Risk-Free Rate	5.25%
Equity Risk Premium	4.0-4.75%
"Bare-Bones" Cost of Equity	9.25-10.0%
Financing Flexibility Allowance	0.50%
Return on Equity	9.75-10.5%

6.1.2 DCF Test

Ms. McShane describes "the Discounted Cash Flow approach as proceeding from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the riskiness of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the investor's required return (or capitalization rate) as the rate that equates the price of the stock to the discounted value of future cash flows."

Due to the dearth of quoted utility companies in Canada and analysts' forecasts thereof, Ms. McShane applies her test to a sample of 14 relatively low-risk U.S. gas and electricity utilities that were included to serve as a proxy for a Canadian low-risk benchmark utility (Exhibit B-1, Tab 2, Appendix C). To determine investors' growth expectations, Ms. McShane uses both Value Line (an independent research firm) forecasts of earnings growth as well as I/B/E/S (the major data base that provides long term consensus forecasts) consensus forecasts of utility equity analysts. Ms. McShane found no evidence of upward bias in the I/B/E/S consensus forecasts; indeed, she cites studies which find that investment analysts' forecasts serve as a better surrogate for investors' expectations than historic growth rates.

In her first application of the DCF model, Ms. McShane applies a constant growth DCF model to her sample which results in a DCF cost of equity of 8.8 percent (Exhibit B-1, Tab 2, Schedule 20). Her second application of the DCF model uses analysts' forecasts for five years and a normal growth in the U.S. economy of 5.5 percent per annum thereafter, which gives a result of 9.7 percent (Exhibit B-1, Tab 2, Schedule 22).
Ms. McShane estimates an indicated "bare-bones" required return on equity in the range of 8.8-9.7 percent or approximately 9.25 percent. To her "bare bones" required return Ms. McShane adds 50 basis points. This is the same amount as that added to her ERP test, but arises for different reasons. Ms. McShane finds a "disconnect" between the DCF return investors expect to earn on the current market value of their common equity investments and what they expect the utility to earn on the book value of their investments. To mitigate this problem, she augments her DCF result by 50 basis points (Exhibit B-1, Tab 2, line 2393).

6.1.3 Comparable Earnings Test ("CE")

Ms. McShane describes the CE as "arising from the notion that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. Since regulation is a surrogate for competition, the opportunity cost principle entails permitting utilities the opportunity to earn a return commensurate with the levels achievable by competitive firms facing similar risk."

To select a sample of Canadian companies of reasonably comparable investment risk to a benchmark low-risk utility, Ms. McShane takes all 432 companies on the Toronto Stock Exchange ("TSX") in Global Industry Classification Standard sectors 20-30 (being Industrials, Consumer Discretionary and Consumer Staples). From this list she removes companies which, in the period 1993-2003 had i) missing or negative common equity (368 companies); ii) paid no dividend in any year (21 companies); and iii) thinly traded companies, companies with betas > 1.0, companies with returns with a standard deviation of +/- -1 from average, ranked high risk or speculative, or unrated (17 companies) to arrive at her sample of 17 low-risk Canadian industrials

(Exhibit B-1,Tab 2, Appendix D).

Ms. McShane chooses the period 1993-2004 on the grounds that it covers an entire business cycle and should be representative of a future normal cycle. Ms. McShane assesses the possible need to adjust the results of her CE tests based on a review of the 17 companies' bond ratings, stock ratings and adjusted betas. Accordingly she adjusts the results of her CE tests which had indicated average levels of returns on book equity in the 13 to 13.5 percent range, down to "no less than 13 percent" (Exhibit B-1, Tab 2, line 2540).

6.1.4 Summary

To arrive at her indicated return on equity for a benchmark low-risk utility Ms. McShane applies an "indicative" weighting of 75 percent to her market based tests (ERP and DCF) and 25 percent to CE. As Ms. McShane points out "the answer is not going to come out to four places. Cost of equity doesn't lend itself to that level of precision" (T4: 506). Her indicated return on equity for a benchmark low-risk utility is 10.5 percent, or a premium of 5.25 percent over her estimate of a long Canada bond of 5.25 percent (Exhibit B-1, Tab 2, line 2573).

Ms. McShane addresses the ROE for TGVI as follows:

> "In my opinion, to equate TGVI to the benchmark low risk utility, an allowed common equity ratio of no less than 45-50% would be required (compared to the range of 35-40% for Terasen Gas). Terasen Gas is proposing a 40% common equity ratio for TGVI. I view the proposal as reasonable; however, the difference between the proposed 40% and the indicated range of 45-50% (mid-point of 47.5%) requires an incremental equity risk premium relative to the benchmark low risk utility return. Applying the same approach as detailed in Schedule 29 for Terasen Gas, the difference between the proposed 40% common equity ratio and a 47.5% common equity ratio warrants an incremental equity risk premium for TGVI relative to the benchmark low risk utility of 60-120 basis points (mid-point of 90 basis points). Thus, the 75 basis point incremental equity risk premium proposed for TGVI is reasonable" (Exhibit B-1, Tab 2, pp. 21-2).

6.2 The Intervenors' Methodology

The Intervenors filed the evidence of Dr. Booth, CIT Chair in Structured Finance and Professor of Finance at the Joseph L. Rotman School of Management at the University of Toronto (Exhibit C2-6). Dr. Booth uses the Capital Asset Pricing Model ("CAPM") to derive his estimate of the MRP, and tests the result with a DCF test of U.S. utilities followed by Standard & Poors.

6.2.1 <u>MRP Test</u>

Dr. Booth uses the period 1956-2004 to determine that the Canadian market risk premium of equities over long-term bonds has averaged (on an arithmetic basis) 2.70 percent. Extending the period examined back to 1924 produces a Canadian market risk premium of 5.21 percent. Dr. Booth estimates the current market risk premium to be 4.5 percent.

Dr. Booth examines the betas for utilities based in Canada for a number of five-year periods ending 1984 to 2004, but finds the data distorted by a number of factors, including the market crash of 1987 and the technology boom and bust of 2000 and 2001. Accordingly, for beta he estimates a reasonable range for normal market conditions going forward to be 0.45 to 0.55, which would imply a risk premium in the 2.025 percent to 2.475 percent range, which he adds to his long Canada bond yield forecast of 5 percent to produce an estimate in a range of 7.0 to 7.5 percent.

In addition to his "Classic CAPM" estimate, Dr. Booth uses a two factor CAPM model, which adjusts for estimation problems in the CAPM by directly incorporating the risk of long Canada bonds through a term or interest rate risk premium. The result of this second test produces an estimation of the fair return of 7.25 percent. Dr. Booth places equal weight on both CAPM estimates and took the average (7.25 percent) as being a reasonable estimate. To this estimate he adds a 50 basis point flotation cost allowance to produce a best estimate of 7.75 percent for a 275 basis point utility risk premium (Exhibit C2-6, p. 60).

6.2.2 <u>Other Tests</u>

Dr. Booth did not perform any other test to determine a fair return on equity. He did however, examine the DCF estimates for U.S. utilities covered by Standard & Poors for the period 1978-2004 from which he estimates an average return on equity of 10.17 percent from which he deducts the average U.S. Treasury of yield of 7.97 percent to determine a 220 basis point U.S. utility risk premium (Exhibit C2-6, Appendix C).

6.3 Discussion

Considerable evidence was before the Commission Panel as to the most suitable methodology to determine a fair return on equity for a benchmark low-risk Canadian utility. Much of the evidence comprises detailing the shortcomings of each of the methodologies in general and of the witness's applications of the concepts in particular.

The evidence is that up to the 1960s the principal methodology to determine fair rates of return was CE, as, according to Dr. Booth, the DCF method and the ERP method which was derived from the CAPM, were developed in the 1960s. By the 1980s all three methodologies were in use in Canada. In the early 1990s capital markets in Canada fell into considerable turmoil, causing DCF and CE to give unreliable results, which resulted in the ERP becoming the main, if not the sole, methodology used by regulatory bodies in Canada to establish fair rates of return. The concept became embedded in Canadian regulatory methodology with the adoption by many regulatory bodies of the AAM whereby an individual utility's return on equity could be adjusted each year by reference to the change in the Risk Free cost of capital (namely the forecast long Canada bond yield). The DCF and CE methods have never managed to restore themselves to favour in regulatory bodies' eyes with the result that in Canada's most recent generic cost of capital hearing, neither method was accorded any weight by the AEUB in its determination of a generic return on equity. In the United States the DCF and CAPM methods got their start in the 1970s and have survived nearly unchanged as the primary rate of return methods, with the DCF the virtual default method in practically all U.S. regulatory jurisdictions [Exhibit B-3E (Vol. 4), Appendix 74.1].

In the words of Ms. McShane: "I believe that … none of the tests is so superior (sic) to the others that it should be discarded in favour of just using one or two tests … Each test should be viewed as providing some perspective on what a fair return is" (T3: 377).

The Applicants in their submission argue that "A fair and reasonable return is not an arithmetic exercise; no approach is the determination of a fair and reasonable return is perfect. Although the use of a simple test may be appealing in its simplicity, it must be realized that the concept of a fair return is not that simple … TGI and TGVI submit that the Commission should consider all three approaches and give weight to each …" (TGI/TGVI Submissions, p. 35, para. 119).

6.3.1 ERP

Conceptually, the ERP methodology has a great deal of appeal to a regulator. It is derived from the CAPM, which was described in Exhibit B-21 being Chapter 7 of *Financial Theory and Corporate Policy* by Copeland and Weston. It requires the derivation of a risk free rate; an observed risk premium, being the difference between returns on common stocks and government bonds; and a factor known as beta, which is the coefficient of a portfolio or stock's volatility compared to the market as a whole. The Applicants outline the following shortcomings of the CAPM as it is applied to the derivation of an ERP:

Risk-Free Rate

The theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. However, the application of the model typically assumes that the return on the market is highly correlated with the risk-free rate, that is, that the equity market return and the risk-free rate move in tandem.

Similarly, an ROE formula that is predicated on a close tracking between the allowed return and the risk-free rate assumes the risk-free rate and the return on the market are highly correlated. The theoretical CAPM calls for using a risk-free rate, whereas the typical application of the model in the regulatory context employs a long-term government bond yield as a proxy for the risk-free rate. Long-term government bond yields may reflect various factors that render them problematic as an estimate of the "true" risk-free rate, including:

- the yield on long-term government bonds reflects the impact of monetary and fiscal policy;
- yields on long-term government bonds may reflect shifting degrees of investors' risk aversion; and
- long-term government bond yields are not risk-free; they are subject to interest rate risk (Exhibit B-1, Tab 2, Appendix A, p. 2).

Equity Market Risk Premium

The equity market risk premium is typically measured largely by reference to historic data. There are a wide range of views on what constitutes an appropriate period for estimating the historic risk premium, on what constitutes the appropriate averaging technique, and on whether various time-specific or country-specific outcomes diminish the reliability of history as a predictor of the future risk premium (Exhibit B-1, Tab 2, Appendix A, p. 3).

A decade by decade review of Canadian historic risk premiums shows a wide range of realized risk premiums, which would indicate the desirability of using longer rather than shorter periods to measure the premiums, as follows:

Time Period	Stock Returns	Bond Returns	Risk Premiums
1940s	10.0%	3.9%	6.0%
1950s	17.0%	0.4%	16.5%
1960s	10.8%	2.9%	7.9%
1970s	12.1%	6.1%	6.0%
1980s	13.1%	13.7%	-0.6%
1990s	11.6%	11.8%	-0.2%
1995-2004	11.2%	10.9%	0.2%
1947-2004 i)	12.0%	6.9%	5.3%
1956-2004 ii)	10.7%	8.0%	2.7%

i) used by Ms McShane
ii) used by Dr Booth (Schedule 1)

In addition, certain problems exist in Canada but not in the United States when it comes to measuring historic risk premium data. The achieved equity market risk premiums in Canada have been reduced by the performance of the government bond market. The change in Canada's fiscal performance over the past decade, leading to the recent low levels of interest rates, indicates that the historic returns on long-term Government of Canada bonds overstate likely future bond returns, and therefore understates the future equity risk premium (Exhibit B-1, Tab 2, Appendix A, p. 4).

The Canadian equity market is less liquid, less diverse and less populous than the U.S. equity market. The performance of the Canadian equity market as the "market portfolio" has been unduly influenced by a small number of companies (Exhibit B-1, Tab 2, Appendix A, p. 4).

Canadian equity data were "backcast" in 1976 upon the creation of the TSE 300 back to 1956. Accordingly, data prior to 1956, and to a lesser extent data between 1956 and 1976, may be less consistent (T6: 926).

Beta

Impediments to reliance on beta as the sole relative risk measure, as the CAPM indicates, include:

- the assumption that all risk for which investors require compensation can be captured and expressed in a single variable;
- the only risk for which investors expect compensation is non-diversifiable equity market risk; no other risk is considered (and priced) by investors; and

- the assumption that the observed calculated betas (which are simply a calculation of how closely a stock's or portfolio's price changes have mirrored those of the overall equity market) are a good measure of the relative return requirement.

Use of beta as the relative risk adjustment allows for the conclusion that the cost of equity capital for a firm can be lower than the risk-free rate, since stocks that have moved counter to the rest of the equity market could be expected to have betas that are negative (Exhibit B-1, Tab 2, Appendix A, p. 5).

6.3.2 DCF

Dr. Booth points out the shortcomings of the DCF methodology. At page 58 of his testimony he states "It is generally accepted that analysts' earnings forecasts are biased high…This conflict of interest has been most evident in the Internet and Technology fiascos of the late 1990s, when prominent analysts issued strong buy recommendations on the way up and kept them in place on the way down and got sued in the process" (Exhibit C2-6, p. 58).

6.3.3 CE

In Appendix B of his evidence, Dr. Booth identifies five basic problems with the earned rate of return, namely:

- It is an accounting rate of return.
- It is an average not a marginal rate of return.
- It is earned on historic accounting book equity that does not reflect what can be earned on investments today.
- It is based on non-inflation adjusted numbers.
- It varies with the firms selected in the "comparable earnings" sample (Exhibit C2-6, Appendix B).

6.4 Commission Determinations

6.4.1 Two Standards

The Commission Panel accepts the relevance of two separate standards namely the capital attraction standard and the comparable returns standard in establishing a fair return on equity for a benchmark low-risk utility. One standard does not trump the other, neither is one subsumed by the other. Accordingly, the Commission Panel will seek to give weight to each of the three methods placed before it in determining a suitable return for a benchmark low-risk utility.

6.4.2 Relevance of Other Board Decisions

All parties refer in their evidence and their submissions to decisions of other regulatory boards in Canada concerning fair returns. The JIESC warns of the danger of circularity resulting from a regulatory board "relying on what other boards have done." The JIESC continues:

> "On the other hand, one cannot totally ignore the immense amount of effort that has gone into determining fair returns by the NEB, in its generic ROE proceeding, and the AEUB, in its recent generic ROE and capital structure hearing.
>
> The AEUB hearing is the most recent and largest generic ROE hearing ever held in Canada. It went for 33 hearing days, involved 11 utilities, and heard from six expert witness panels.
>
> The AEUB and the NEB decisions should not be applied blindly by this Commission. However, they should be considered carefully, as should evidence of market acceptance of the allowed returns, and the acceptability of their awards to investors." (JIESC Submission, pp. 7-8)

At the November 2005 consensus risk free rate for 2006 of 4.79 percent the returns allowed for 2006 under current mechanisms are as follows:

BCUC – Terasen Gas Inc.	8.29%
NEB – Generic	8.89%
AEUB – Generic	8.93%
Ontario*	8.71%
Newfoundland	8.77%

* October 2005 Consensus
Source: Exhibit B-26

The Commission Panel's view is that it holds generic hearings into a fair return on such an infrequent basis, that there is little danger of circularity should it consider the returns allowed in other jurisdictions to ensure that the return it allows for 2006 is in line with returns allowed to benchmark low risk utilities in other jurisdictions.

6.4.3 Globalization

The Applicant states that since 1994 "Globalization of capital markets means that Canadian utilities are competing for capital with alternative investments world-wide. Globalization of capital markets provides Canadian investors opportunities for higher returns at similar risk levels than available in the domestic market. The returns allowed for Canadian utilities need to recognize that Canadian investors' opportunities are not limited to domestic investments" (Exhibit B-1, Tab 2, p. 5).

Dr. Booth submitted a monograph propounding the thesis that globalization or diversification reduces risk and market risk premium in both markets (Exhibit C2-6, Appendix D).

Dr. Booth, under cross-examination, states, "I generally believe that the US estimates both for the market risk premium and the US estimates from US regulated gas and electric utilities are higher than they would be for Canada. … I would say that they're too high, which means that you cannot take them directly and apply them in Canada. … I would say they're indicative, but my personal opinion would be that they are too high" (T6: 820).

During cross-examination Ms. McShane stated "And so there are a couple of different points: one, that there are opportunities (sc for investors to commit capital globally) and two, that in measuring the risk premium, we need to look beyond Canadian data" (T4: 424).

The Commission Panel agrees with this bifurcation. On the first issue the Commission Panel agrees that while it is now possible for Canadian investors to commit their entire retirement savings capital offshore, there is no evidence that they have been in a huge hurry to do so. Canadian investors face a considerable foreign exchange risk when investing offshore and the Commission Panel does not believe that they set this risk aside on the grounds that, in a perfect world, it should be capable of being hedged or otherwise diversified away.

The Commission Panel is not convinced that the Federal Government's relaxation of foreign content rules in retirement portfolios should be a reason to increase the equity return of a benchmark low-risk utility.

As to the second issue, the Commission Panel is prepared to accept the use of historical and forecast data of U.S. utilities when applied as a check to Canadian data; as a substitute for Canadian data when those data do not exist in significant quantity or quality; or as a supplement to Canadian data when Canadian data give unreliable results. The Commission Panel bases this view on the fact that the U.S. and Canadian economy and capital markets are closely integrated.

6.4.4 Market to book ratios and acquisition premiums

In his evidence, Dr. Booth addresses the issue of market to book ratios of utility companies as follows:

> "This process is akin to someone investing in a savings account where a judge has to determine the correct savings rate each period that can be withdrawn from the fund. The important implication is that if the judge (regulator) is successful then the savings will always be worth their original investment. This is the meaning of the basic result in finance that fair means that the market to book ratio equals one. The only thing different about utilities, as compared to the savings example, is that there is some very minor business risk" (Exhibit C2-6, p. 74).

In Schedule 30 of his evidence, Dr. Booth graphically tracks the market to book ratios of a number of utility holding companies in Canada over the period. In addition, he observes the premiums paid by companies to acquire utility companies or utility assets and reaches the conclusion that regulatory bodies have been overly generous in their allowed returns on equity. In particular the Intervenors point to the acquisition of the shares of TI by KMI at an estimated market to book ratio of 2.7 to 1 to demonstrate that the Commission's formulaic approach to setting returns on equity has been overly generous and demonstrates that no upward revision to the existing ROE is warranted. Indeed, they argue that the Commission Panel accept Dr. Booth's recommendation, which would lower the benchmark return on equity.

Market to book ratios are a function of a stock's price divided by the book value of a share of its common equity. A stock's price is a function of what the market will pay for it and is either expressed by analysts and investors as a multiple of earnings or in a utility's case as the yield on its dividend. In neither case has a regulatory body any degree of control over the quantum of either the multiple or the actual dividend paid (McShane, T3: 139). Evidence before the Commission Panel is that market to book ratios of utilities (especially in the U.S.) have been below parity in the past. The Commission Panel agrees with Copeland and Weston (see Section 6.3.1 above) that all investors select efficient portfolios and that the market is simply the sum of all investors' individual holdings. Accordingly, the price paid for a utility share will vary over time depending on the changes in individual risk tolerances. The proper application of the CAPM model should remove the possibility of over generous returns, but over time will not prevent the market from valuing a utility's stock at prices which are both greater than and lower than its book value.

So far as concerns acquisition premiums, the Commission Panel has addressed the Kinder Morgan acquisition elsewhere in this Decision. So far as concerns other acquisitions the Commission Panel is mindful of the AEUB Panel's decision:

> "The Board agrees with the Applicants that there are a number of factors impacting market-to-book ratios of utility holding companies and that one has to be cautious making inferences regarding the regulated utilities. The Board also agrees that there may be strategic factors affecting the price that is paid to acquire a utility.
>
> …The Board also recognizes that, in some cases, a premium might be paid for regulated assets in anticipation of significant future growth in rate base, to achieve geographic diversification or to obtain a foothold in a new market. However, parties are also aware of the constraints placed on regulated utilities with respect to affiliate transactions, particularly those with unregulated affiliates.
>
> In the absence of such strategic factors, the Board would not expect a prudent investor to pay a significant premium unless the currently awarded returns are higher than that required by the market. The Board acknowledges the views of some parties that payment of a premium over

> book value for a regulated utility indicates that the recent ROE awards may have been higher than required by the market. The Board is not aware of the strategic factors that may have affected the price paid to acquire Alberta utilities in recent years. Nevertheless, the experience regarding the market-to-book values of utilities and the experience … in recent years gives the Board some comfort that its recent ROE awards have not been too low" (Exhibit A3-1, p. 28).

The Commission Panel agrees with the AEUB that acquisition premiums may result from a number of strategic factors which are unrelated to the establishment of a fair return for a benchmark low-risk utility. The Commission will continue its practice of allowing utilities subject to its jurisdiction, to earn a fair return on the value of their investment in property, the value of which does <u>not</u> include a premium on acquisition.

6.4.5 <u>ERP</u>

It is clear the ERP methodology is the "gold standard" for Canadian regulators and the Commission Panel will give primary weight to its application and results. In doing so, however, the Commission Panel will need to apply judgment to the evidence before it.

<u>CAPM Method</u>

Risk Free Rate

For the purposes of establishing a return on equity, the Commission Panel accepts the consensus 30-year bond yield estimate for 2006, of 5.25 percent proposed by Ms. McShane. In Section 3 of the Decision, the Commission Panel discusses the methodology it should follow in effecting the transition of its present AAM to that which it now finds appropriate.

Arithmetic vs. Geometric Average

The Intervenors introduced the concept of the use of a geometric, rather than an arithmetical average to calculate the total returns on stocks and bonds (Exhibit C2-6, Appendix E, p. 1-3). The Applicant advocates the use of the arithmetic average, citing Ibbotson Associates "the expected equity risk premium should always be calculated using the arithmetic mean" (Exhibit B1, Tab 2).

The Commission Panel notes that the AEUB in its Generic Cost of Capital decision stated:

> "In the Board's view, when a forecast is based on the historic average, the arithmetic average MRP represents the best estimate of the short-term return and the geometric average represents the best estimate of the long-term return. The Board has not been persuaded that it should change its practice of using the arithmetic average. Consequently, the Board will maintain its

practice of using the arithmetic average rather than the geometric average" (Exhibit A3-1, p. 19).

Accordingly, the Commission Panel accepts the use of the arithmetic average for the purpose of determining the MRP in this hearing.

Market Risk Premium (MRP)

The Commission Panel observes that the evidence before it consists of the following average Market Risk Premium percentages:

		Canada	**US**
Applicant	1947-2004	5.3	7.0
Intervenor	1956-2004	2.70	4.65

and that both witnesses make adjustments to these results to arrive at their recommendations. In the Commission Panel's view a MRP of 5.8 percent is appropriate, given the Canadian experienced premiums since the Second World War, adjusted upwards in part to recognize both the fact that bond returns will most likely decrease in future years, and in part to recognize U.S. returns. Dr. Booth's two-factor model is not helpful in assisting the Commission Panel in determining an appropriate MRP.

Beta

The Commission Panel agrees with the evidence that the estimation of betas using actual five-year data ending December 31, 2004 (five years being the typical period for calculating betas) would give unreliable results given the technology boom followed by the bust in the years 2000 and 2001. Both witnesses were obliged to make considerable adjustments to arrive at recommended betas, Ms. McShane to her 0.60 to 0.70 and Dr. Booth to his 0.45 to 0.55. The Commission Panel believes that an appropriate estimate of beta or the relative risk factor of a benchmark low risk factor versus the overall equity market is 0.50. The Commission Panel is hopeful that such adjustments will not be necessary since the five-year data no longer include the technology boom/bust.

Historic Utility Risk Premium Test

The Commission Panel believes that this test avoids the estimation of a beta and thus suffers from one less shortcoming than the MRP test. On the basis of Ms. McShane's evidence that utility risk premiums in Canada over the period 1956 to 2004 were 4.4 percent, the Commission Panel is prepared to give weight to this number in arriving at its ERP.

DCF-Based Equity Risk Premium Test

The Commission Panel believes that Ms. McShane's sample of seven U.S. A-rated pure-play gas distribution companies, which indicates an average risk premium of 4.2 percent, is too small to use other than as a check on her other findings.

Financing Flexibility Adjustment

Both Ms. McShane and Dr. Booth add a Financing Flexibility Adjustment of 50 basis points to their ERP test results. In Ms. McShane's view the adjustment is necessary to cover flotation costs; a cushion for unanticipated capital market conditions and recognition of the fairness principle (Exhibit B-1, Tab 2, line 2160). Dr. Booth added a 50 basis point flotation allowance (Exhibit C2-6, p. 50). Both witnesses agree that the ERP test produces a bare bones cost of capital which should result in a market to book ratio of one. In Ms. McShane's words, "At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility will be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity" (Exhibit B-1, Tab 2, p. 82).

Dr. Booth observes that flotation costs can be calculated using the constant growth model and that the allowance could vary depending on a firm's dividend payment ratio and the ability to expense certain issue costs for tax purposes. He does, however, note at page 50 of his evidence "Note that with 5% issue costs, the idea is that the stock should sell at a market to book ratio of 1.053, so that it will net out to book value on any new issue. With utility market to book ratios vastly in excess of 1.052 it is difficult to rationalize any flotation cost allowance, since it is unlikely that there will ever be any dilution" (Exhibit C2-6, Footnote 19).

He concludes "However, I normally add 50 basis points as a cushion to the direct estimates in line with this (sic) practice of many Boards" (Exhibit C2-6, p. 50).

The Commission Panel notes that this issue received some attention during the AEUB generic hearing, but that it was not enough to convince the AEUB to change the 50 basis point flotation cost allowance used in recent decisions (Exhibit A3-1, p. 29).

The Commission Panel tends to agree that it is difficult to rationalize any flotation cost allowance since there was little, if any, evidence placed before it of utilities trading at market to book ratios, which would justify a flotation cost allowance addition to their return on equity. Elsewhere in this decision the Commission Panel addresses market to book ratios and the need to establish a fair rather than lowest possible return. Accordingly, the Commission Panel will not automatically add a 50 basis point surcharge to whatever return it deems appropriate, but will exercise its judgment each time.

6.4.6 DCF Test

The Commission Panel notes that the DCF test is the most widely used test by regulatory bodies in the United States. Of the three methodologies before it, the DCF test is the only one to use current and prospective data to derive its results. The major criticism of the DCF method is that it relies on analysts' forecasts, which may be biased upwards. The Commission Panel does not find Dr. Booth's comments helpful in that his observations mostly cover U.S. technology analysts and the scandal on Wall Street concerning inappropriate analyst behaviour in an investment banking milieu. The Commission Panel finds that Dr. Booth's use of DCF estimates for U.S. Utilities covered by Standard & Poors, which included "multi-utilities" and energy marketing firms, should not be used as representative of U.S. utility returns. The Commission Panel is more persuaded by Ms. McShane's evidence which compares Value Line and I/B/E/S forecasts and finds no upward bias in the latter. Accordingly, the Commission Panel will give weight to Ms. McShane's first DCF Test, which yielded an indicated return of 8.8 percent. The Commission Panel agrees that this is a "bare bones" cost of equity, to which the addition of a "pure" flotation allowance of 25 basis points is required.

6.4.7 Comparable Earnings

Ms. McShane continues her practice of including in her evidence a study of the returns on book equity earned by a sample of low risk Canadian industrials in the period 1993-2004. This would suggest that low risk companies in Canada are earning an average of approximately 13 percent on their book equity.

On cross-examination, Dr. Booth agreed that some of the "problems" with the CE test also appear in the process of setting rates under regulation, notably that both use an accounting rate of return; it is an average, not a marginal, return; it is based on historic book equity; and based on non-inflation adjusted numbers. This leaves the sample selection itself. The Commission Panel recognizes that the sample selection can lead to very different results, which is why regulatory bodies are reluctant to re-embrace Comparable Earnings.

Dr. Booth reminded the Commission Panel that the last jurisdiction in Canada to use Comparable Earnings used to adjust the results as follows:

> "And Dr. Cannon tended to be the board (sc OEB) witness and he would do comparable earnings with market-to-book adjustments. And stretching my memory, but Ms. McShane I think estimated correctly that you'd look at rates of returns and try to work out what these rates of returns from non-regulated first would be if they had to have a market to book ratio of 1.5 or 1.2, which was sort of the target for regulated firm" (T6: 935).

The Commission Panel believes that there is not enough evidence before it to determine if such an adjustment is merited or how it might be accomplished. The Commission Panel is of the view that for these reasons it can give little or no weight to Ms. McShane's CE test results. However, the Commission Panel is not convinced that the CE methodology has outlived its usefulness, and believes that it may yet play a role in future ROE hearings.

6.4.8 Conclusion

In the Commission Panel's view, the suitable return on equity for a benchmark low-risk utility is 9.145 percent, assuming a 30-year long Canada bond yield of 5.25 percent, for a premium of 3.895 percent.

6.5 Impact of the Commission Panel's Determination

6.5.1 Impact on TGI

The Commission Panel determines that TGI is the benchmark low-risk utility. For 2006 TGI's ROE will be 8.80 percent viz 9.145 minus (.75*(5.25-4.79), on an equity component of capital structure of 35 percent, which the Commission Panel earlier determined to be appropriate. Based on Exhibit B-13, the Commission Panel believes the impact on TGI's 2006 revenue requirement will be a net increase of $1.9 million over TGI's approved 2005 revenue requirements, as follows:

	$ million
Increase in capital structure to 35%	4.742
Decrease in ROE to 8.80% from 9.03%	(2.842)
	1.900

6.5.2 Impact on TGVI

The Commission Panel determines that a suitable premium to TGVI over the benchmark low-risk utility ROE is 70 basis points. For 2006 TGVI's ROE will be 9.5 percent on an equity component of capital structure of 40 percent, which the Commission Panel earlier determined to be appropriate. Since TGVI was earning 9.53 percent in 2005, the net impact on TGVI's revenue requirement in 2006 will be approximately $1.7 million.

6.5.3 Other B.C. utilities

Other B.C. utilities whose ROE will be automatically affected by the Commission Panel's determination, effective January 1, 2006, include:

	Benchmark	**Premium**	**2006 ROE**
FortisBC	8.80	0.40	9.20
Pacific Northern Gas – W	8.80	0.65	9.45
Pacific Northern Gas – NE	8.80	0.40	9.20
BC Hydro (1)	8.80	0.00	8.80

(1) on a post-tax equivalent basis

Dated at the City of Vancouver, in the Province of British Columbia, this 2nd day of March 2006.

Original signed by:
Robert H. Hobbs
Panel Chair

Original signed by:
Anthony J. Pullman
Commissioner

Views of Commissioner Milbourne

I have had the opportunity of reading the determinations and reasons of the majority of the Panel in final draft form.

With the exception noted below, I respectfully dissent from my colleagues' findings with respect to the Capital Structure and Return on Equity for TGI and TGVI. I do not find that the totality of evidence before the Panel, and the authorities cited, make a persuasive case for any change from the status quo.

I concur with their findings in Section 3 with respect to the Annual Adjustment Mechanism. This change, if adopted for changes in long Canada bond yields above and below 6 percent would accordingly raise the allowed ROE for 2006 from 8.29 percent to approximately 8.60 percent for the Low Risk Benchmark Utility.

Original signed by:
R.J. Milbourne
Commissioner

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-14-06

SIXTH FLOOR, 900 HOWE STREET, BOX 250
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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Application by
Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") ("the Companies")

To Determine the Appropriate Return on Equity ("ROE") and Capital Structure to be Used in Setting the Rates of the Companies Commencing January 1, 2006

and

To Review and Revise the Automatic Adjustment Mechanism Used in Calculating the ROE Allowed in Rates for Public Utilities Regulated by the BC Utilities Commission
("the Application")

BEFORE: R.H. Hobbs, Chair
R.J. Milbourne, Commissioner March 2, 2006
A.J. Pullman, Commissioner

O R D E R

WHEREAS:

A. On July 22, 2004, TGI wrote to the Commission requesting that the Commission convene a hearing to review return on equity and capital structure. By Order No. G-88-04 the Commission determined that a hearing was not warranted at that time but concluded that such a review would be appropriate in the Fall of 2005 in time for implementation January 1, 2006; and

B. By Application dated June 30, 2005, the Companies submit that: 1) the allowed returns on equity of both Companies should be increased to an appropriate level, 2) the common equity component in the capital structure of both Companies should be increased to properly reflect the risks of the Companies, and 3) the current ROE adjustment mechanism should be reviewed and revised to provide the Companies with a fair and adequate return on equity in future years; and

C. By Order No. G-69-05, the Commission established a Procedural Conference to be held on Wednesday, August 3, 2005 in Vancouver, B.C.; and

D. In a letter dated August 25, 2005, the Joint Industry Electricity Steering Committee ("JIESC") requested that the Chair decide not to sit on the Panel to avoid compromising the unbiased appearance of the proceeding and the procedural fairness all parties are entitled to expect; and

…/2

E. By Letter No. L-67-05 dated August 5, 2005, the Commission Panel defined the scope of the proceeding, determined that other utilities would not have the same status as other Intervenors in the proceeding, and established an approved Regulatory Timetable including an Oral Public Hearing to review the Application to commence on Monday, November 14, 2005; and

F. By Letter No. L-81-05 dated September 29, 2005, the Commission denied the request by the JIESC that the Chair should not sit on this matter; and

G. An Oral Public Hearing was held in Vancouver commencing on November 14, 2005 and ending on November 18, 2005; and

H. Written Argument was filed by the Companies on December 5, 2005 and by the Intervenors on or before December 20, 2005. Reply Argument was filed by the Companies on January 5, 2006 and an Oral Phase of Argument was held on January 17, 2006; and

I. The Commission Panel has determined that a change to the Capital Structures of the Companies, the Returns on Equity allowed a low-risk benchmark utility, and the utility-specific equity risk premium for TGVI is in the public interest.

NOW THEREFORE the Commission orders as follows to be effective January 1, 2006:

1. The appropriate common equity component allowed in the capital structure of TGI is 35 percent.

2. The appropriate common equity component allowed in the capital structure of TGVI is 40 percent.

3. The approved return on equity for the benchmark low-risk utility is 9.145 percent assuming a 30-year long Canada bond yield of 5.25 percent. For 2006 this results in an approved return on equity for TGI of 8.80 percent.

4. The approved return on equity for TGVI is 70 basis points greater than the benchmark low-risk utility return, namely 9.5 percent.

5. Other B.C. utilities whose returns on equity are established relative to that of the benchmark low-risk utility may adjust their rates accordingly subject to Commission approval.

DATED at the City of Vancouver, in the Province of British Columbia, this 2nd day of March, 2006.

BY ORDER

Original signed by:

Robert H. Hobbs
Chair

LIST OF APPEARANCES

G.A. FULTON	Commission Counsel
C. JOHNSON M. GHIKAS	Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
P. MACDONALD	B.C. Old Age Pensioners' Organization Council of Senior Citizens' Organizations Federated Anti-Poverty Group End Legislated Poverty West-End Seniors Network Tenants Rights Action Coalition B.C. Coalition of People with Disabilities
G.K. MACINTOSH, Q.C. D. BENNETT	FortisBC Inc.
J.D.V. NEWLANDS	Elk Valley Coal Corporation
R.B. WALLACE	Joint Industry Electricity Steering Committee British Columbia Utility Customers
C. WEAFER	Commercial Energy Consumers Association of British Columbia
A. WAIT	Himself

J.W. Fraser R. Gorter E. Cheng D. Chong	Commission Staff
Allwest Reporting Ltd.	Court Reporters

LIST OF WITNESSES

RANDY JESPERSEN SCOTT THOMSON DAVID BRYSON	Terasen Gas Inc. (Panel 1)
KATHLEEN MCSHANE	Terasen Gas Inc. (Panel 2)
DR. LAURENCE D. BOOTH	British Columbia Utility Customers: (Joint Industry Electricity Steering Committee, Commercial Energy Consumers Association of British Columbia The Lower Mainland Large Gas Users Association The British Columbia Old Age Pensioners' Organization et al.)

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated July 8, 2005 and Order No. G-69-05 establishing a Procedural Conference
A-2	Letter dated July 8, 2005 requesting the Regulated Utilities to provide their preliminary positions on the participation and the coordination of evidence of all regulated utilities
A-3	Letter No. L-58-05 dated July 19, 2005 regarding appointment of Commissioner
A-4	Letter dated July 21, 2005 advising that Commissioner O’Hara will not be appointed to the Panel for this Proceeding
A-5	Letter dated August 2, 2005 enclosing draft Regulatory Agenda for discussion at the Procedural Conference
A-6	Letter No. L-67-05 dated August 5, 2005 defining the scope for review of the Application and issuing an updated Regulatory Timetable
A-7	Letter dated August 8, 2005 to Terasen Gas and Terasen Gas (Vancouver Island) responding to the JIESC’s request (Exhibit C2-2) for a full description of the Chair’s involvement, on or off the record, in British Columbia or Alberta, relating to ROE, ROE adjustment mechanisms and capital structure issues
A-8	Letter dated August 11, 2005 to Pacific Northern Gas Ltd. responding to its request for clarification of PNG's status pursuant to Commission Letter No. L-67-05
A-9	Letter and Commission Information Request No. 1 dated August 12, 2005 to Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
A-10	Letter dated August 26, 2005 requesting comments from Registered Intervenors on the JIESC request to have the Chair step down (Exhibit C2-3)
A-11	Letter dated September 13, 2005 and Commission Information Request No. 2
A2-1	Letter dated September 2, 2005 from Commission Counsel commenting on the JIESC request to have the Chair step down (Exhibit C2-3)

EXHIBIT LIST

Exhibit No.	Description
A-12	Letter dated September 29, 2005 – Reasons Regarding JIESC Request
A-13	Letter dated October 20, 2005 – Information Request No. 1 to Utility Customers
A-14	Letter dated November 10, 2005 – Commencement of Hearing
A-15	Letter dated November 10, 2005 – Appointment of Commissioner A.J. Pullman
A-15a	Commission Submission at Oral Hearing – Response to BCUC IR No. 1
A-16	Commission Submission at Oral Hearing – TGI Response to IR
A-17	Commission Submission at Oral Hearing – TGI Pricing Supplement No. 2
A-18	Commission Submission at Oral Hearing – TGI Pricing Supplement No. 3
A-19	Commission Submission at Oral Hearing – TGI-TGVI Cross Examination – Policy Panel
A-20	Commission Submission at Oral Hearing – BMO Nesbitt Burns – Consolidated Summary Sheet
A-21	Commission Submission at Oral Hearing – Adjustment to Cost of Service
A-22	Commission Submission at Oral Hearing – TGVI ROE Allowed and Achieved Calculation
A-23	Commission Submission at Oral Hearing – TGVI Statements of Earnings
A-24	Commission Submission at Oral Hearing – Witness Aid-Evidence Weights
A-25	Commission Submission at Oral Hearing – ICBC Statement of Investment Policy and Procedures
A-26	Commission Submission at Oral Hearing – Canadian Ratings Research Update-Terasen Inc. Purchase by Kinder Morgan Inc.
A-27	Submission At Oral Hearing – News Release From FortisBC Dated November 10, 2005 Announcing $100 Million Debenture Offering
A-28	Submission At Oral Hearing – Document From Standard & Poors Dated January 2002 Headed "S&P/TSX Capped Indices"

EXHIBIT LIST

Exhibit No.	Description
A-29	Letter dated December 19, 2005 approving the JIESC's request for an extension of time to file its closing argument material (Exhibit C2-22)
A3-1	Submission at Oral Hearing – Alberta Energy and Utilities Board-Generic Cost of Capital Decision dated July 2, 2004
A3-2	Submission at Oral Hearing -Decision of the Board of Commissioners of Public Utilities, Newfoundland and Labrador, in the matter of the 2003 general rate application filed by Newfoundland Power Inc., the Board order PU19-2003
A3-3	Submission at Oral Hearing - Decision of the Regis (Action Number D-99-11)
A3-4	Submission At Oral Hearing - Supreme Court Of Canada Decision re: Northwest Utilities
A3-5	Submission At Oral Hearing – B.C. Electric Railway Company Supreme Court Of Canada Decision Dated 1960
A3-6	Order No. G-126-05 and Negotiated Settlement dated November 30, 2005 on TGVI's 2006/07 Revenue Requirements Application

APPLICANT DOCUMENTS

Exhibit No.	Description
B-1	**TERASEN GAS INC and TERASEN GAS (VANCOUVER ISLAND) INC.** Application dated June 30, 2005 to determine the appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism
B-2	E-mail dated July 20, 2005 providing a letter from Terasen Gas (Whistler) Inc. and Terasen Gas (Squamish) Inc. in response to Commission letter of July 8, 2005 (Exhibit A-2)
B-3	Letter dated September 2, 2005 filing responses to Commission Information Request No. 1
B-4	Letter dated September 7, 2005 responding to the JIESC request that the Commission Chair step down from the Panel established to review the Return on Equity Application
B-5	Letter dated September 30, 2005 filing responses to the following

EXHIBIT LIST

Exhibit No.	Description
	Information Requests:
	Commission Information Request No. 2 Al Wait Information Request No. 1 Commercial Energy Consumers Information Request No. 1 JIESC-BCOAPO-CEC (Dr. Booth) Information Request No. 1 Vancouver Island Gas Joint Venture Information Request No. 1
B-6	Letter dated October 5, 2005 – Revised certain rate comparative Figures and Tables in June 30, 2005 Application
B-7	Letter dated October 20, 2005 – Information Request No. 1 to Dr. Laurence D. Booth
B-8	Submission at Oral Hearing – Direct Testimony of R.L. (Randy) Jesperson Direct Testimony of Scott Thomson Direct Testimony of David Bryson
B-9	Submission at Oral Hearing – Opening Statement on Behalf of TGI and TGVI
B-10	Submission at Oral Hearing – 2006 Forecast Allowed ROE & Capital Structure
B-11	Submission at Oral Hearing – 30yr Bond Issues in Canada with BBB rating
B-12	Submission at Oral Hearing – Recorded Actual TGI Volumes – TJs
B-13	Submission at Oral Hearing – Undertaking-Transcript Page 231
B-14	Submission at Oral Hearing – Undertaking Transcript Page 259
B-14A	Submission at Oral Hearing – Undertaking Transcript Page 807
B-15	Submission at Oral Hearing – Terasen Management's Discussion and Analysis dated November 3, 2005
B-16	Submission at Oral Hearing – Undertaking Transcript Page 259
B-17	Submission at Oral Hearing – Undertaking Transcript Page 260
B-18	Submission at Oral Hearing –Ratings Direct Research-Canadian Utility Regulation Reassessed as a Ratings Factor

EXHIBIT LIST

Exhibit No.	Description
B-19	Submission at Oral Hearing – Global Credit Research Document dated October 14, 2005
B-20	Submission at Oral Hearing – Kinder Morgan's Historical Equity and Debt/Total Capitalization Ratios
B-21	Submission at Oral Hearing – Financial Theory and Corporate Policy
B-22	Submission at Oral Hearing – Market and Individual Stock Graph
B-23	Submission at Oral Hearing – Commission Transcript dated April 12, 1994
B-24	Submission at Oral Hearing – GICS to Companies
B-25	Submission at Oral Hearing - Generic Roe Calculation For 2006 Based On Current Formula
B-26	Letter dated November 25, 2005 – ROE 2006 Estimates
B-27	Letter dated January 3, 2006 filing the December 19, 2005 Moody's Investors Service Announcement
B-28	Letter dated January 20, 2006 amending the TGI/TGVI January 19, 2006 letter regarding interest coverage discussed at page 1071 of the Transcript

INTERVENOR DOCUMENTS

C1-1	**CENTRAL HEAT DISTRIBUTION LIMITED** - Notice of Intervention dated July 8, 2005 from John S. Barnes
C2-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC)** - Notice of Intervention dated July 13, 2005 from R.B. Wallace
C2-2	Letter dated August 5, 2005 to Commission Counsel requesting a full description of the Chair's involvement, on or off the record, in British Columbia or Alberta, relating to ROE, ROE adjustment mechanisms and capital structure issues from the time the Chair joined West Kootenay, presumably some time before 1994 until he left Aquila in 2001 or 2002
C2-3	Letter dated August 25, 2005 requesting that the Commission Chair step down from the Panel established to review the Return on Equity Application

EXHIBIT LIST

Exhibit No.	Description
C2-4	Letter dated September 9, 2005 responding to Intervenor submissions
C2-5	Information Request No. 1 dated September 14, 2005
C2-6	Letter dated October 11, 2005 – Evidence of Dr. Laurence Booth
C2-7	E-mail dated November 4, 2005 – Responses to Terasen Gas Information Request No. 1
C2-8	E-mail dated November 4, 2005 – Responses to FortisBC Information Request No. 1
C2-9	E-mail dated November 4, 2005 – Responses to Commission Information Request No. 1
C2-10	Submission at Oral Hearing – Review of OEB Guidelines for setting ROE
C2-11	Submission at Oral Hearing – BMO Corporate Debt Research regarding Terasen Inc. – Kinder Morgan Acquisition Appears Credit Negative for Bondholders
C2-12	Submission at Oral Hearing – Globe and Mail clip from October 30, 2001 regarding “BC Gas financing proves it’s the silly season”
C2-13	Submission at Oral Hearing – TGI Credit Rating Report
C2-14	Submission at Oral Hearing – OEB September 7, 1993 Transcript
C2-15	Submission at Oral Hearing – Electric Load Forecast
C2-16	Submission at Oral Hearing – BMO Research Report regarding BC Gas to Acquire Centra Gas British Columbia
C2-17	Submission at Oral Hearing – RBC Capital Markets document dated August 10, 2005
C2-18	Submission at Oral Hearing – Corporate Financial Analysis
C2-19	Submission at Oral Hearing – Basic Variables-Single Year Changes Year-End to Year-End

EXHIBIT LIST

Exhibit No.	Description
C2-11A	Submission at Oral Hearing – Gas Distribution Sector-10 yr Indicative Spreads
C2-20	Submission at Oral Hearing – Public, Power & Utilities Bulletin dated August 10, 2005
C2-21	Responses to Undertakings at Transcript Volume 6, pp. 825, 827 and 903-4
C2-22	Letter dated December 14, 2005 requesting a one day extension to the filing of the JIESC Argument
C2-23	Letter dated December 21, 2005 requesting the Commission to re-open the evidentiary record
C2-24	Undertaking at Transcript Page 1054 - Letter dated January 22, 2006 regarding the issuance of Preferred Shares
C2-25	Undertaking at Transcript Page 1071 – Letter dated January 22, 2006 regarding Interest Coverage
C3-1	**THE BC OLD AGE PENSIONERS ORGANIZATION ET AL.** - Notice of Intervention dated July 15, 2005 from Jim Quail, The British Columbia Public Interest Advocacy Centre
C3-2	Letter dated September 2, 2005 filing comments regarding the JIESC request to have the Chair step down (Exhibit C2-3)
C4-1	**ENBRIDGE GAS DISTRIBUTION** - Notice of Intervention dated July 18, 2005 from Lorraine Chiasson
C4-2	E-mail dated July 26, 2005 regarding Enbridge Gas Distribution contact information
C5-1	**ELK VALLEY COAL CORPORATION** - Notice of Intervention dated July 20, 2005 from J. David Newlands
C6-1	**UNION GAS LIMITED** - Notice of Intervention dated July 21, 2005 from Patrick McMahon

EXHIBIT LIST

Exhibit No.	Description
C7-1	**INLAND INDUSTRIALS** - Notice of Intervention dated July 25, 2005 from David Bursey, Bull, Housser & Tupper LLP
C8-1	**CANADIAN OFFICE AND PROFESSIONAL UNION** - Notice of Intervention dated July 21, 2005 from Pat Junnila
C9-1	**LOWER MAINLAND LARGE GAS USERS ASSOCIATION** - Notice of Intervention dated July 26, 2005 from Christopher Weafer, Owen•Bird
C10-1	**ALAN WAIT** - Notice of Intervention dated July 26, 2005
C10-2	E-mail dated July 26, 2005 with reasons for intervention
C10-3	Information Request No. 1 dated September 14, 2005
C11-1	**RANDALL JANG** - Notice of Intervention dated July 28, 2005
C12-1	**FORTISBC INC.** - Notice of Intervention dated July 28, 2005 from George Isherwood
C12-2	Letter dated October 20, 2005 – Information Request No. 1 to JIESC, CEC and BCOAPO
C12-3	Submission at Oral Hearing – Rates of Return on Common Equity at Various Bond Yield Levels
C13-1	**MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES** - Notice of Intervention dated July 26, 2005 from Stirling M. Bates
C14-1	**TRANSCANADA PIPELINES LIMITED** - Notice of Intervention dated July 28, 2005 from James Bartlett and Patrick M. Keys
C15-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY** - Notice of Intervention dated July 29, 2005 from Tony Morris

EXHIBIT LIST

Exhibit No.	Description
C15-2	Letter dated September 2, 2005 filing comments regarding the JIESC request to have the Chair step down (Exhibit C2-3)
C16-1	**AVISTA ENERGY CANADA** - Notice of Intervention dated July 29, 2005
C17-1	**HEATING, VENTILATING & COOLING ASSOCIATION** – Web registration dated July 29, 2005 from Nelle Maxey
C17-2	Letter of Comment dated August 10, 2005
C17-3	Letter dated August 26, 2005 supporting the JIESC's request that the Chair step down from the Panel
C18-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA** – Notice of Intervention dated July 29, 2005 from Christopher Weafer
C18-2	Information Request No. 1 dated September 14, 2005 from Christopher Weafer
C19-1	**PACIFIC NORTHERN GAS LTD.** – Notice of Intervention and Comments on the Generic ROE proceeding dated July 28, 2005 from Craig Donohue
C19-2	Letter dated August 10, 2005 requesting clarification of PNG's status in light of Commission Letter No. L-67-05
C20-1	**VANCOUVER ISLAND GAS JOINT VENTURE** – Notice of Intervention dated August 26, 2005 from Karl E. Gustafson, Lange Michener
C20-2	Letter dated September 2, 2005 filing comments regarding the JIESC request to have the Chair step down (Exhibit C2-3)
C20-3	Information Request No. 1 received September 15, 2005
C21-1	**HOWE SOUND PULP AND PAPER LIMITED PARTNERSHIP** – Notice of Intervention dated August 30, 2005 from Pierre G. Lamarche

EXHIBIT LIST

Exhibit No.	Description
INTERESTED PARTY DOCUMENTS	
D-1	Letter dated July 8, 2005 from the Rental Owners and Managers Association of BC requesting Interested Party status
LETTERS OF COMMENT	
E-1	Letter of Comment dated July 22, 2005 from Reiner Teschinsky Letter of Comment dated August 30, 2005 from Reiner Teschinsky

GLOSSARY AND ABBREVIATIONS

Acronym	**Term**
Act or UCA	Utilities Commission Act
AEUB	Alberta Energy and Utilities Board
“Applicants”, “Companies”	Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
“Application”	Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. - Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism dated June 30, 2005
AAM	Automatic Adjustment Mechanism
BC Gas	BC Gas Utility Ltd.
BC Hydro	British Columbia Hydro and Power Authority
BCOAPO	The British Columbia Old Age Pensioners’ Organization et al.
BCUC or Commission	British Columbia Utilities Commission
CAPM	Capital Asset Pricing Model
CBRS	Canadian Bond Rating Service
CCRA	Commodity Cost Reconciliation Account
CE	Comparable Earnings
CEC	Commercial Energy Consumers Association of British Columbia
CRTC	Canadian Radio-Television and Telecommunications Commission
DBRS	Dominion Bond Rating Service
DCF	Discounted Cash Flow
Enbridge or EGDI	Enbridge Gas Distribution Inc.
EGNB	Enbridge Gas New Brunswick
ERP	Equity Risk Premium
GJ	Gigajoule
GMI	Gaz Metro
IBES	Institutional Brokers Estimates System
ICP	Island Cogeneration Project
JIESC	Joint Industry Electrical Steering Committee

GLOSSARY AND ABBREVIATIONS

KMI	Kinder Morgan, Inc.
MCRA	Midstream Cost Reconciliation Account
Moody’s	Moody’s Investors Service
MRP	Market Risk Premium
NEB	National Energy Board
OEB	Ontario Energy Board
O&M	Operating and Maintenance Costs
PBR	Performance-Based Rates or Performance Based Rate-Making
PNG	Pacific Northern Gas Ltd.
RDDA	Revenue Deficiency Deferral Account
ROE	Return on Equity
RSAM	Revenue Stabilization Adjustment Mechanism
S&P	Standard & Poors
Terasen Gas or TGI	Terasen Gas Inc.
TGS	Terasen Gas (Squamish) Ltd.
TGVI	Terasen Gas (Vancouver Island) Inc.
TI	Terasen Inc.
TJ	Terajoule
Union	Union Gas Limited
Value Line	Value Line, Inc.
VINGPA	Vancouver Island Natural Gas Pipeline Agreement

BCUC Letter, Return on Common Equity for a Low-Risk Benchmark Utility for the Year 2007

ROBERT J. PELLATT
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

LETTER NO. L-75-06

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
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VIA E-MAIL

November 23, 2006

Mr. Scott Thomson
Vice President, Finance and Regulatory Affairs
Terasen Gas Inc.
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Mr. David Bennett
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regulatory@fortisbc.com

Mr. C.P. Donohue
Director, Regulatory Affairs & Gas Supply
Pacific Northern Gas Ltd.
950 - 1185 West Georgia Street
Vancouver, B.C. V6E 4E6
cdonohue@png.ca

Dear Sirs:

Re: Return on Common Equity for a
Low-Risk Benchmark Utility for the Year 2007

Pursuant to the Commission's Decision dated June 10, 1994 regarding Return on Common Equity and Order No. G-35-94, and as amended by Order No. G-80-99, Order No. G-109-01 and Order No. G-14-06, the Commission has determined that the current ROE automatic adjustment mechanism results in an allowed return on common equity of 8.37 percent for a low-risk benchmark utility in 2007. The calculation and other documentation in support of this finding are attached.

The appropriate ROE in 2007 for individual utilities will incorporate the risk premium for each utility relative to the low-risk benchmark.

Yours truly,

Original signed by:

Robert J. Pellatt

RG/cms
Attachment

cc:

Mr. R. Brian Wallace
Bull, Housser & Tupper
rbw@bht.com

Ms. Joanna Sofield
Chief Regulatory Officer
British Columbia Hydro and Power Authority
regulatory.group@bchydro.com

Mr. Marcel Reghelini
Director, Regulatory Affairs
British Columbia Transmission Corporation
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Mr. Jim Quail
Executive Director
The British Columbia Public Interest Advocacy Centre
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BCUC Regulated Utilities

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Fax to:

Yukon Electrical Company Limited
867-668-3965

Calculation of Allowed 2007 Rate of Return on Common Equity
For A Low-Risk Benchmark Utility
(Per Commission Order No. G-35-94,
Amended by Order No. G-80-99, Order No. G-109-01 and Order No. G-14-06)

A forecast of long-term Canada bonds is developed based on the Consensus Economics forecast of 10-year bonds (step 1) and the observed spread between 10- and 30-year bonds over a defined period (step 2). This establishes a forecast yield for long Canada bonds (step 3).

1.	Ten Year Canada Bond Yield – end of February, 2007 (Consensus Economics, November 2006 Consensus Forecast)	4.1%	
	Ten Year Canada Bond Yield – end of November, 2007 (Consensus Economics, November 2006 Consensus Forecast)	4.2%	
	Average of 3 and 12 Month Forecasts	4.15%	
2.	Add average yield spread between 10-year and 30-year bonds as reported in the Financial Post for all trading days in October, 2006.	0.069%	
3.	Equals forecast yield on long-term Canada bonds		4.219%

As per Commission Order No. G-14-06, the approved benchmark return on equity (ROE) is 9.145 percent assuming a 30-year long Canada bond yield of 5.25 percent. Where the forecast yield is greater or less than 5.25 percent, a sliding scale adjustment raises or lowers the benchmark ROE by 75 percent of the change in the forecast yield on long-term Canada Bonds (step 4). The unrounded allowed ROE in percentage terms is rounded to the nearest 2 decimal places (step 5).

4.	Unrounded allowed ROE based on sliding scale adjustment: 9.145 – (0.75 * (5.25 – 4.219))	8.372%
5.	Allowed ROE	8.37%

Approval of 2005 Revenue Requirements, 2005-2024 System Development Plan and 2005 Resource Plan, FortisBC BCUC G-52-05 2005 Decision

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IN THE MATTER OF

the Utilities Commission Act, RSBC 1996, Chapter 473, as amended

and

An Application by FortisBC Inc.
for Approval of 2005 Revenue Requirements,
2005-2024 System Development Plan and 2005 Resource Plan

BEFORE: L.F. Kelsey, Commissioner and Panel Chair
P.G. Bradley, Commissioner May 31, 2005

O R D E R

WHEREAS:

A. On November 26, 2004, FortisBC Inc. ("FortisBC") submitted its 2005 Revenue Requirements Application, which also included its Transition Plan and 2005 Capital Plan ("Submission 1"). On the same date, under separate cover, FortisBC also filed its 2005-2024 System Development Plan ("Submission 2"). On December 21, 2004, FortisBC submitted its 2005 Resource Plan ("Submission 3"); and

B. In Submission 1 FortisBC requested approval of a 2005 Revenue Requirement of $184,388,000 and a general rate increase of 4.4 percent; and

C. On December 14, 2004, the Commission issued Order No. G-111-04, establishing a series of Workshops, a Pre-hearing Conference, and approving an interim rate increase of 3.7 percent, effective January 1, 2005, subject to refund with interest calculated at the average prime rate of the principal bank with which FortisBC conducts its business; and

D. A Pre-hearing Conference was held on January 21, 2005 in Kelowna, B.C. to discuss the major issues to be examined, and the steps and timetable for an Oral Public Hearing. Registered Intervenors and FortisBC made their submissions for consideration by the Commission; and

E. Order No. G-14-05 dated January 24, 2005, set out an amended Regulatory Timetable and Issues List and established an Oral Public Hearing to commence on March 21, 2005 in Kelowna, B.C.; and

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F. By letter dated January 27, 2005, FortisBC requested a revision to the Regulatory Timetable and process to include a Negotiated Settlement Process ("NSP"). The Commission issued Letter No. L-9-05 dated January 28, 2005, rejecting the request for an NSP because it was concerned that FortisBC and its predecessors have gone for many years without a detailed review of the utility operations in an oral public hearing process; and

G. On March 10, 2005, FortisBC filed a revised 2005 Revenue Requirements Application ("Submission 4") reflecting the impact of updated 2004 actual energy sales and financial results. In Submission 4 FortisBC sought approval for a revised 2005 Revenue Requirement of $179,980,000 and a general rate increase of 4.1 percent, effective January 1, 2005; and

H. On March 18, 2005, FortisBC filed a second revised 2005 Revenue Requirements Application ("Submission 5") primarily reflecting the impact of updates to 2004 power purchase incentive adjustments and 2005 income tax expense. In Submission 5 FortisBC sought approval for a revised 2005 Revenue Requirement of $179,250,000 and a general rate increase of 3.6 percent, effective January 1, 2005; and

I. The Oral Public Hearing proceeded as scheduled in Kelowna, B.C. on March 21 through March 24, 2005. During the Oral Public Hearing, on March 22, 2005, FortisBC filed a third revised 2005 Revenue Requirements Application ("Submission 6") incorporating a correction to the 2004 Actual and 2005 Forecast Mid-Year Rate Base. In Submission 6 FortisBC sought approval for a revised 2005 Revenue Requirement of $179,991,000 and a general rate increase of 4.1 percent, effective January 1, 2005; and

J. Written Final Arguments and Reply Arguments were completed on April 29, 2005; and

K. The Commission Panel has considered Submissions 1 through 6 and all of the related evidence and arguments.

NOW THEREFORE the Commission orders as follows:

1. FortisBC is directed to file complete financial schedules showing:

   (a) The requested 2005 Revenue Requirement of $179,991,000 as per Submission 6;
   (b) All adjustments set out in the Decision issued concurrently with this Order; and
   (c) The final resultant 2005 Revenue Requirement and general rate increase.

   The Commission approves the final resultant 2005 Revenue Requirement and general rate increase consistent with all adjustments set out in the Decision issued concurrently with this Order.

2. If the final general rate increase is less than the 3.7 percent general rate increase granted on an interim refundable basis as per Order No. G-111-04, then refunds should be made to customers as soon as practicable, with interest calculated at the average prime rate of the principal bank with which FortisBC conducts its business. FortisBC is directed to file all relevant refund calculations with the Commission.

…/3

3. If the final general rate increase is greater than the 3.7 percent general rate increase granted on an interim refundable basis as per Order No. G-111-04, the additional monies will be recovered through a rate rider based on forecast consumption for the period July 1, 2005 to December 31, 2005. FortisBC is directed to file all relevant rate rider calculations with the Commission.

4. FortisBC is also directed to comply with all other determinations and instructions set out in the Decision that is issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 31st day of May 2005.

BY ORDER

Original signed by:

L.F. Kelsey
Commissioner and Panel Chair

Attachment

IN THE MATTER OF

FORTISBC INC.

2005 REVENUE REQUIREMENTS APPLICATION
2005-2024 SYSTEM DEVELOPMENT PLAN
2005 RESOURCE PLAN

DECISION

MAY 31, 2005

Before:

L.F. Kelsey, Commissioner and Panel Chair
P.G. Bradley, Commissioner

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1.0 INTRODUCTION

1.1 Background and Historical Context

In 1986 UtiliCorp United and UtiliCorp BC applied to the British Columbia Utilities Commission ("Commission") to acquire a reviewable interest in West Kootenay Power and Light Company Ltd. Following an extensive review, that application was approved by the Commission. The West Kootenay Power and Light Company Ltd. name remained for some time, was subsequently changed several times, eventually to become Aquila Networks Canada (British Columbia) Ltd. ("Aquila(BC)") (the "Utility").

In October 1998, as part of its Preliminary 1999 Revenue Requirements and Incentive Mechanism Review Application, the Utility applied for an Order that a Negotiated Settlement Process ("NSP") be implemented. Commission Order No. G-123-98 approved that application. Following negotiations with Intervenors, wherein a settlement was reached, Commission Order No. G-134-99 approved the November 22, 1999 Settlement Agreement for the period beginning January 1, 2000 and ending December 31, 2002. The terms of the 1999 Settlement Agreement required that the Utility institute an NSP and an Annual Review process to allow the public to examine the filed material, to submit other issues for determination by the Commission and to discuss all issues prior to the final rate application being made.

On November 15, 2002, the Utility requested that the 1999 Settlement Agreement be extended for a period of one year ending December 31, 2003, filing a Preliminary 2003 Revenue Requirements Application in support. Commission Order No. G-83-02 established a 2002 Annual Review and an NSP to determine rates for 2003. The proceedings were held in Penticton B.C. in January 2003. A Public Information Town Hall Meeting was scheduled for those parties not able to participate in the Annual Review. Commission Order No. G-10-03 approved the Negotiated Settlement as issued. This Settlement was a simple extension of the 2000-2002 rate adjustment mechanism approved by the November 22, 1999 Settlement Agreement. The Utility agreed at that time to provide a detailed revenue requirements application for 2004 that would contain a full analysis in support of any proposed rebasing of in the cost categories.

On November 19, 2003, the Utility filed a Preliminary 2004 Revenue Requirements Application with the Commission. Due to the impending sale of the Canadian business of Aquila(BC) to Fortis Inc. and the potential for restructuring, the Utility proposed a one-year extension of the current Settlement Agreement, which was due to expire on December 31, 2003 subject to certain changes as described in the Application. Further, the Utility proposed an NSP to determine the 2004 Revenue Requirements and the parameters of the Incentive Mechanism.

The Utility also requested that the 2003 Annual Review of its performance be scheduled prior to the NSP.

By Order No. G-6-04 the Commission approved an NSP to determine rates for 2004. Following negotiations, Commission Order No. G-38-04 approved the terms of the negotiated settlement agreement.

As contemplated in the Preliminary 2004 Revenue Requirements Application, on December 1, 2003, Fortis Pacific Holdings Inc. ("Fortis Pacific") applied pursuant to Section 54 of the Utilities Commission Act ("UCA") for an Order approving the acquisition of a reviewable interest in Aquila Networks Canada (British Columbia) Ltd. from Aquila Networks British Columbia Ltd. On the same date, Aquila Networks Canada (British Columbia) Ltd applied pursuant to Section 54(5) of the UCA for approval to register a transfer of 100 percent of its Common Shares to Fortis Pacific.

Following a written hearing, the Commission, by Order No. G-39-04 approved the acquisition by Fortis Pacific of a reviewable interest in Aquila Networks Canada (British Columbia) Ltd. The company was renamed FortisBC Inc ("FortisBC").

In response to a Commission information request during the acquisition hearing, FortisBC stated that it anticipated that it would file a general rate application in the fourth quarter of 2004 that would "set out in detail the plans for re-establishing the Utility on a stand-alone basis." FortisBC also stated that the rate application would "provide a basis for full public scrutiny of a more detailed plan including a definitive timetable, a forecast of proposed costs and an assessment of customer benefits, as well as a reasonable record for the Commission's consideration of matters relating to this issue."

1.2 FortisBC Filings and Procedural Summary

On November 26, 2004, FortisBC filed its 2005 Revenue Requirements Application with the Commission ("November Application") (Exhibit B-1). FortisBC applies for an Order, pursuant to the applicable provisions of the UCA including Sections 23, 45, 57, 60, and 61, approving the November Application for the purpose of setting rates and other ancillary matters. Included with this filing, and in compliance with Commission Order No. G-39-04, FortisBC submitted its Transition Plan outlining the steps being taken to move the utility to a stand-alone basis. FortisBC included its 2005 Capital Plan with its November Application and filed under separate cover its 2005-2024 System Development Plan (Exhibit B-2). It filed these plans to address high priority work needed to maintain and expand the electrical system to meet its obligation to provide reliable electricity service to its customers. FortisBC filed its 2005 Resource Plan (Exhibit B-4) in accordance with the Commission's Resource Planning Guidelines and the Commission's directives to utilities in this regard.

FortisBC's November Application requests approval of a general rate increase of 4.4 percent, reflecting principally an increased rate base, an increased cost of financing that rate base and a forecast increase in 2005 expenses, including operating and maintenance expenses and power purchases. The November Application included a request for an interim refundable general rate increase of 4.4 percent, effective January 1, 2005. The increase was based, in part, on a proposal to increase the equity risk premium of FortisBC from 40 to 75 basis points. In response to a Commission staff request, FortisBC determined that the general rate increase would equal 3.7 percent if derived on the basis of its existing equity risk premium of 40 basis points. On December 14, 2004, the Commission issued Order No. G-111-04 approving for FortisBC an interim rate increase of 3.7 percent, effective January 1, 2005, subject to refund with interest calculated for the refund period at the average prime rate of the principal bank with which FortisBC conducts its business. By this Order the Commission also established a series of Application Workshops and a Pre-hearing Conference.

The Commission held the Pre-Hearing Conference in Kelowna, B.C. on January 21, 2005, wherein the Commission Panel considered submissions by participants on finalizing the issues, process steps and regulatory schedule for the proceeding. As part of its consideration of process steps, the Commission Panel heard submissions by parties on whether certain issues would be appropriately reviewed by Technical Committees.

Following the Pre-Hearing Conference, on January 24, 2005 the Commission issued Order No. G-14-05, which set out an amended Regulatory Timetable and Issues. Commission Order No. G-14-05 established an Oral Public Hearing ("Hearing") to commence on March 21, 2005 in Kelowna, and specified that issues associated with the Load Forecast, Demand Side Management ("DSM"), Power Purchases, and Capital Additions would be reviewed by four separate Technical Committees as an adjunct to the Hearing. The Commission directed each Technical Committee to submit a report with recommendations to the Commission by Monday, March 14, 2005, one week prior to the commencement of the Hearing.

By letter dated January 27, 2005, FortisBC requested that the regulatory timetable and process be revised to include an NSP (Exhibit B-8). FortisBC indicated that on the condition that the NSP was successful it would defer its application for an increase to its equity risk premium until the fall of 2005 in anticipation of a Commission process regarding the return on equity adjustment mechanism at that time. FortisBC reported that its proposed revision to the regulatory timetable and process was supported by most Intervenors.

The Commission issued Letter No. L-9-05 on January 28, 2005 rejecting FortisBC's request for an NSP for 2005. The Commission was concerned that FortisBC and its predecessors have gone for many years without a detailed review of the utility operations in an oral public hearing process, while noting that in each of the last two settlements the participants agreed that an oral public hearing was timely and should occur the following year. At the request of FortisBC, and for reasons that are a matter of public record, oral public hearings did not occur. The Commission believed that it was timely to review the finances and revenue requirement of the new B.C.-based utility in an oral public hearing this year. The Commission commented that following such a detailed review and decision, it may then be timely to consider an NSP thereafter. The Commission also noted that successful work by the four Technical Committees would go a considerable distance to streamlining the Hearing.

On March 9, 2005, FortisBC filed the reports of the DSM and Load Forecast Technical Committees (Exhibits B-17 and B-18, respectively). Each Committee recommended that there would be no need to call hearing panels in their respective subject areas. On March 11, 2005, FortisBC filed the reports of the Capital Additions and Power Purchases Technical Committees (Exhibits B-20 and B-21, respectively). The Capital Additions and Power Purchases Technical Committees reported that the meetings were helpful, but recommended that these matters should be addressed at the Hearing.

On March 11, 2005, the Commission wrote to Registered Intervenors requesting that they indicate by March 16, 2005 whether or not they were supportive of the recommendations of the DSM and Load Forecast Committees that there is no need to call hearing panels in their respective subject areas (Exhibit A-14). The Commission indicated in its letter that it would consider no response to indicate support of the Committee recommendations. Out of those intervenors that did not participate in the work of these Committees, the Commission received one letter of support, from the B.C. Old Age Pensioners Association *et al.* ("BCOAPO"), and zero letters of no support. By letter dated March 17, 2005 the Commission accepted the recommendations of the DSM and Load Forecast Committees that there is no need to call hearing panels in the respective subject areas (Exhibit A-16).

On March 10, 2005, FortisBC filed a revised 2005 Revenue Requirements Application (the "Revised Application") (Exhibit B-19). FortisBC indicates that its Revised Application reflects the impact of updates to 2004 actual results on 2005 energy sales and revenue forecasts, and 2004 incentive adjustments. FortisBC reported that its Revised Application includes revisions arising from events subsequent to the November Application, such as FortisBC's Capital Tax appeal and changes to property tax assessment procedures. FortisBC's Revised Application sought approval of a 2005 Revenue Requirement of approximately $180.0 million, and a general rate increase of 4.1 percent, effective January 1, 2005.

On March 18, 2005, FortisBC filed a second revised 2005 Revenue Requirements Application (the "Second Revised Application") reflecting the impact of updates to 2004 power purchase incentive adjustments and 2005 income tax expense (Exhibit B-25). The Second Revised Application also reflects actual issue costs related to FortisBC's Series 04-01 Senior Unsecured Debentures equal to $2,091,000, which is less than the forecast of $2,150,000 in the initial Application. The Second Revised Application requests approval to defer and amortize the actual amount. FortisBC's Second Revised Application seeks approval of a 2005 Revenue Requirement of approximately $179.3 million, and a general rate increase of 3.6 percent, effective January 1, 2005.

The Hearing proceeded as scheduled in Kelowna on March 21 through March 24, 2005.

On March 22, the second day of the Hearing, FortisBC filed a third revised 2005 Revenue Requirements Application (the "Third Revised Application") (Exhibit B-26). FortisBC indicated that the Third Revised Application incorporates a correction to the 2004 Actual and 2005 Forecast Mid-Year Rate Base; namely that the Mid-Year Rate Base had been understated in the Second Revised Application by approximately $3.0 million in 2004 and $8.3 million in 2005. FortisBC states that the understatement of Rate Base was caused by the incorrect reduction of net additions to plant in service by the amount of new Contributions in Aid of Construction ("CIAC"). FortisBC's Third Revised Application seeks approval of a 2005 Revenue Requirement of approximately $180.0 million, and a general rate increase of 4.1 percent, effective January 1, 2005.

Following the Hearing, written argument was received by FortisBC on April 15, 2005 ("FortisBC Argument"). On April 22, 2005, the Commission received argument from Natural Resources Industries ("NRI", "NRI Argument"), Interior Municipal Electric Utilities ("IMEU", "IMEU Argument"), Mr. Alan Wait ("Mr. Wait", "Wait Argument"), Kootenay-Okanagan Electric Consumers Association ("KOECA", "KOECA Argument"), and BCOAPO ("BCOAPO Argument"). FortisBC filed its reply argument on April 29, 2005 ("FortisBC Reply Argument").

FortisBC adopted the convention in its written argument that its November Application, together with its Revised Application, Second Revised Application and Third Revised Application, would be collectively referred to as the "Application". The Commission uses the same referencing convention in this Decision unless it is necessary to refer to a specific filing, as appropriate.

FortisBC summarizes in its written argument that it seeks an Order of the Commission (FortisBC Argument, pp. 3-5):

- approving a 2005 Revenue Requirement of $179,991,000;
- approving the deferral of the cost of regulatory and related activities and the issue cost of the Series 04-1 Senior Unsecured Debentures in the amount of $2,091,000;
- approving the amortization of: the issue cost of the Series 04-1 Senior Unsecured Debentures in the amount of $2,091,000 over ten years commencing on January 1, 2005; the costs incurred in FortisBC's 2004 Revenue Requirements negotiated settlement process; and the costs of the 2005-2024 System Development Plan and 2005 Resource Plan, in an aggregate amount of $900,000 over five years commencing on January 1, 2005;
- approving the continuation of the current Demand Side Management and Power Purchase incentive mechanisms for 2005;
- approving the continuation of the flow through to customers of forecast and actual property tax, provincial water fees, and the Power Purchase expense related to the Brilliant contracts for 2005;
- approving the flow-through treatment of the costs of capacity block power purchases forecast for November and December 2005;
- approving an operating and Maintenance expense program with a forecast value of $36,173,000 and a sharing mechanism for expense above or below this amount;
- approving a cost of capital for rate making purposes that reflects a return on equity 75 basis points above that set by the Commission for a benchmark low-risk utility and a common equity ratio of 40 percent of total capitalization;
- acknowledging that the 2005 Capital Plan satisfies the requirements of Section 45 of the Utilities Commission Act and that specified capital projects are in the public interest;
- acknowledging that the 2005 Resource Plan meets the requirements of Section 45 of the Utilities Commission Act, and is in the public interest;
- acknowledging that the 2005 Demand Side Management ("DSM") Expenditures Plan meets the requirements of Section 45 of the Act, and is in the public interest;
- approving a change in the accounting treatment of certain PowerSense costs, such that the costs in the amount of $85,000 are charged to capital rather than operations;
- approving deferral and recovery in 2006 of higher income tax expense that will arise in 2005 if the new Capital Cost Allowance rates announced in the February 23, 2005 Federal Budget are not enacted prior to December 31, 2005; and
- approving a general rate increase of 4.1 percent effective January 1, 2005.

The following sections of this Decision address, in turn, the issues associated with the 2005 Revenue Requirements Application, the 2005 Capital Plan and 2005-2024 System Development Plan, and the 2005 Resource Plan.

2.0 2005 REVENUE REQUIREMENTS APPLICATION

2.1 Forecasts

2.1.1 Load Forecast

FortisBC describes its service area as experiencing population growth at an increased rate over the last several years. FortisBC observed that in 2004 the growth in energy consumption and the number of customer accounts has been significantly above the long term population growth rate in its service area. To account for these patterns of growth, FortisBC modified its load forecast methodology to decouple population growth from its forecast of energy consumption and customer accounts for the period 2004-2009. FortisBC anticipates that by 2009, energy consumption and customer growth rates will return to the long term rates of population growth. FortisBC normalized all temperature sensitive load data to eliminate the effect of temperature prior to conducting its load forecast and associated statistical analyses. In its November Application, FortisBC forecast a total gross load of 3,368 GWh, subsequently adjusted downward by 78 GWh to 3,290 GWh based on updates to 2004 actual data, and a revised industrial forecast (Exhibit B-1, pp. 4, 9; Exhibit B-19, p. 4). The components of this change are described in greater detail below. The following sections include a summary of the load forecast for each customer class in turn.

Residential

The Residential load forecast is comprised of a forecast of customer accounts and a forecast of use per customer.

FortisBC forecasts the growth rate in its customer accounts based on the long-term linear trend in population growth rates in its service area, augmented by adjustments that reflect actual and expected growth in the short-term. The short-term adjustments encompass the decoupling of the forecast from population growth, as described above. FortisBC forecasts 85,926 Residential customer accounts by 2005 year-end (Exhibit B-1, pp. 4, 10; Exhibit B-12, Q. 38.1, Q. 41.0).

FortisBC forecasts Residential use per customer based on a 19-year average annual decline rate between 1985 and 2003 of 67 kWh/customer. FortisBC indicates that possible explanations for this decline rate are the availability of more efficient electrical appliances and declining dependence on electricity as a primary source of energy for heating and cooling (Exhibit B-1, p. 4; Exhibit B-12, Q. 41.0).

Based on these components, FortisBC initially forecast a Residential load of 1,064 GWh. Subsequent to its November Application, FortisBC adjusted this forecast downward by 10 GWh, to 1,054 GWh, to reflect the impact of actual and normalized 2004 Residential energy consumption that was below forecast despite strong growth in Residential customer accounts (Exhibit B-1, p. 9; Exhibit B-19, p. 4).

General Service

FortisBC's General Service class includes commercial and small industrial customers, as well as schools, hospitals and recreation facilities. FortisBC indicates that it is more difficult to forecast energy consumption in this class because of the diversity in customer size and the lumpiness of load additions.

Applying the same methodology as it uses for the Residential class, FortisBC forecasts 10,306 customer accounts by 2005 year-end. FortisBC forecasts General Service use per customer based on a 25-year average annual incline rate of 26 kWh/customer (Exhibit B-1, pp. 5, 10; Exhibit B-12, Q.42.0). Based on these components, FortisBC initially forecast a General Service load of 570 GWh. Subsequent to its November Application, FortisBC adjusted this forecast downward by 24 GWh, to 546 GWh, to reflect the impact of actual and normalized 2004 General Service energy consumption that was below forecast despite strong growth in General Service customer accounts (Exhibit B-1, p. 9; Exhibit B-19, p. 4).

Industrial

FortisBC forecasts its Industrial load by estimating the annual energy consumption of Celgar, its single largest industrial customer, and adding this amount to a forecast of the remainder of Industrial load determined on the basis of the historical relationship of this portion of Industrial load to overall system load. FortisBC initially estimated Industrial load of 343 GWh, including Celgar load of 65 GWh based on recent Celgar projections, or nearly 20 percent of overall Industrial load. Subsequent to its November Application, FortisBC adjusted this forecast downward by 34 GWh, to 309 GWh, to reflect a new 2005 load forecast projection by Celgar of 31 GWh (Exhibit B-1, pp. 5, 9; Exhibit B-19, p. 4).

Wholesale

FortisBC's Wholesale class is comprised mainly of municipal electric utilities, with a corresponding composition of residential, commercial and industrial customers. Given that this load is largely sensitive to population growth trends, FortisBC forecasts Wholesale consumption based on the relationship between population growth trends and temperature normalized historical consumption in this class (Exhibit B-1, p. 6).

FortisBC initially forecast Wholesale load of 964 GWh. Subsequent to its November Application, FortisBC adjusted this forecast downward by 6 GWh, to 958 GWh, to reflect the impact of actual and normalized 2004 Wholesale energy consumption that was below forecast (Exhibit B-1, p. 9; Exhibit B-19, p. 4).

Irrigation and Lighting

FortisBC forecasts Irrigation load of 47 GWh based on a five-year average load, and assumes that this level will remain constant for the duration of the forecast period. Similarly, forecast Lighting load of 10 GWh is assumed to remain constant for the duration of the forecast period.

System Losses

FortisBC forecasts losses of 369 GWh on the basis that annual losses consistently amount to roughly 12 percent of historical net system load. FortisBC adjusted its forecast losses downward by 3 GWh, to 366 GWh, based on the updates to the load forecast of the respective customer classes described above.

Load Forecast Technical Committee

Commission Order No. G-14-05 specified that issues associated with the Load Forecast would be reviewed by a Technical Committee as an adjunct to the Hearing. The Committee comprised FortisBC and Commission staff as well as Registered Intervenors that expressed an interest to participate. The Commission directed the Load Forecast Technical Committee to submit a report with recommendations to the Commission one-week prior to the commencement of the Hearing (Exhibit A-4).

FortisBC filed the Report of the Load Forecast Technical Committee on March 9, 2005 (Exhibit B-18). The Committee considered several methodological issues in detail over the course of two meetings; most notably a review of the assumptions underlying the regression analyses for the Residential and General Service use per customer forecasts. Further detail of the issues discussed, and the undertakings completed by FortisBC in response, may be referenced in the Report (Exhibit B-18). Committee members concluded that there were no serious methodological concerns with the load forecast. Committee members were provided with the revised forecast, as summarized above, prior to the filing of the report. No concerns were raised about the revised forecast.

The Committee suggested that FortisBC improve upon the communication and transparency of the technical detail and associated calculation spreadsheets for the load forecast. The Committee recommended that there would be no need to call a load forecast panel at the Hearing. After canvassing comment from those Registered

Intervenors that did not participate in the Load Forecast Technical Committee, the Commission accepted this recommendation (Exhibit A-16). A load forecast panel was not called at the Hearing and no load forecast issues were otherwise addressed in the Hearing. No written submissions on the load forecast were received in argument by any party.

Commission Panel Determinations

The Commission Panel has reviewed the FortisBC Load Forecast and the Report of the Load Forecast Technical Committee. **The Commission Panel accepts the revised FortisBC gross load forecast of 3,290 GWh.**

The Commission Panel is mindful of the Technical Committee suggestion that FortisBC improve upon the communication and transparency of the technical detail and associated calculation spreadsheets for the load forecast. Accordingly, the Commission Panel encourages FortisBC to improve its efforts in this regard. The Commission Panel also encourages FortisBC to consult with its Wholesale customers to determine whether any other means exist to obtain a more rigorous and comprehensive load forecast for this customer class. In addition, the Commission Panel has some concern about whether FortisBC's load forecast adequately accounts for diverse regional characteristics that exist across its service area, particularly in light of its reliance on more general population trends in its load forecast methodology. The Commission Panel encourages FortisBC to investigate alternatives to its current load forecast methodology to determine whether any benefit can be gained by segmenting its load forecast by specific regions in its service area, as FortisBC would define them.

2.1.2 Power Purchase and Wheeling Forecast

In its November Application, FortisBC forecast Power Purchase and Wheeling expenses (including water fees) of $74.26 million (Exhibit B-1, Tab 7). Power Purchase expenses alone are forecast to be $62.44 million for 2005, compared to an estimated amount for 2004 of $60.39 million. FortisBC noted that the Power Purchase expense forecast contains uncertainty with respect to load volumes and resource uncertainty. The resource uncertainty is related to market purchases required to supply a small shortfall between its firm resources and forecast loads. In its Revised Application FortisBC reduced the Forecast Power Purchase Expense to $59.45 million as a result of a change in load forecasts. This change reduced total forecast Power supply costs (including wheeling and water fees) to $71.01 million (Exhibit B-19, and Exhibit B-26).

As discussed in the 2005 Resource Plan, FortisBC meets the majority of its needs through its own generation plants and from long-term power purchase agreements, as well as from BC Hydro's Rate Schedule 3808. The remaining amount (mainly for capacity at peak load periods) is acquired through spot market purchases or block purchases from TeckCominco ("Cominco"). In 2004 these purchases were made in advance of need through the purchase of blocks of capacity from Cominco and through the purchase of a call option from Avista Energy (Exhibit B-1, Tab 7, pp. 10-11). The 2005 forecast includes market purchases and Cominco block purchases for January and February (actual) and November and December (estimated). The estimated amount of block purchases from Cominco is for 25MW in November and 100MW in December at estimated prices of $65.20/MW and $65.40/MW, respectively. Spot Market purchases for capacity (with a small amount of energy) are purchased year round depending on whether spot market prices are better than under BC Hydro Rate Schedule 3808. However, in the year 2005 for the months of January and February, and November and December, when FortisBC may be forced to purchase from the market, the forecast prices are 113 mills/KWh (11.3 cents/kWh). These prices are based on the Avista Energy Report and adjusted for the most valuable hours in the block (Exhibit B-1, Tab 7, p. 12). FortisBC provided an example of how this calculation is made in Appendix 1 to Exhibit B-21.

In past years FortisBC forecasted that its shortfall would be made up by market purchases because it does not have a firm contract with Cominco. However, the company typically was able to enter contracts late in the year at below market prices. The resulting difference was shared 50-50 between the company and its customers. This arrangement has been criticized because it appeared that the block purchases, although not firm, were predictable.

For this application FortisBC is proposing that the block purchases for November and December be taken out of the incentive mechanism and be treated as flow-through expense (Exhibit B1, Tab7, p 11).

No intervenor expressed objections to the Power Purchase forecast.

Commission Panel Determinations

The Commission Panel approves the forecast Power Purchases expense of $71,010,000, as revised by Exhibit B-19. Approval of the Power Purchase expense mechanism is addressed in this Decision in Section 2.4: 2005 Incentive Sharing Mechanisms.

2.2 Common Equity Component and Return on Common Equity

FortisBC applies to the Commission for approval of a cost of capital for rate making purposes that reflects a common equity ratio of 40 percent of total capitalization and a return on equity of 75 basis points above that set by the Commission for a benchmark low-risk utility.

In support of this application, FortisBC filed expert evidence titled *Opinion on Capital Structure and Equity Risk Premium for FortisBC*, prepared by Kathleen C. McShane ("Ms. McShane") of Foster Associates Inc., an economic consulting firm (Exhibit B-1, Tab 5). Ms. McShane concluded that a 40 percent common equity ratio, representative of FortisBC's actual capital structure, is reasonable but should be viewed as the minimum necessary to provide adequate financing flexibility. Ms. McShane recommends that FortisBC be allowed an incremental risk premium of 50 to 100 basis points (a mid-point of 75 basis points) relative to that applicable to a low risk benchmark utility.

BCOAPO filed expert evidence titled *Business Risk, Capital Structure and ROE for FortisBC*, prepared by Dr. Laurence D. Booth ("Dr. Booth"), a professor of finance in the Rotman School of Management at the University of Toronto (Exhibit C5-5). Dr. Booth recommends that the current 40 percent common equity ratio be maintained, but that the current FortisBC incremental risk premium of 40 basis points should be reduced to zero rather than increased to 75 basis points.

The following sections summarize the evidence and submissions on these issues, and the Commission's determinations in this regard.

2.2.1 Direct Evidence of Ms. McShane

Ms. McShane's approach to assessing the appropriate capital structure and return on equity ("ROE") for FortisBC was based on: 1) evaluating the reasonableness of the actual capital structure that has been maintained by FortisBC in terms of its compatibility with the business risks of the utility; and 2) accepting the Commission's ROE for a benchmark low risk utility as a point of departure for estimating the equity risk premium for FortisBC at the proposed capital structure (Exhibit B-1, Tab 5, p. 3).

Ms. McShane's evidence is premised on the stand-alone principle and an assessment of the market, supply and regulatory business risks and financial risks faced by of FortisBC. In regard to the stand-alone principle, Ms. McShane comments that there is no reason that FortisBC's capital structure or the fair return on equity should change simply because the identity of the shareholder has changed, but should continue to be premised on the risks faced by FortisBC. Ms. McShane notes that each of the Fortis utilities is financed on a stand-alone basis, so FortisBC's credit will be assessed on its own business risks and ability to generate adequate cash flows (Exhibit B-1, Tab 5, pp. 4-5).

Business Risk

Ms. McShane assesses FortisBC's business risks while noting the following factors:

- FortisBC is a relatively small utility serving a generally rural service area;
- Major industries served by FortisBC include forestry/pulp and paper, agriculture and tourism;
- Population growth in its service area has been strong over the past decade;
- Economic growth in B.C., dependent on the strength of commodity prices and the strength of the US economy, is expected to continue to outpace that of the country as a whole;
- Recent NAFTA rulings in favour of the Canadian forest industry may ultimately be beneficial;
- Increased demand for B.C.'s exports, not just those of the forest products industry, is anticipated from the economies of the Pacific Rim;
- Long-term B.C. economic growth is expected to be at a somewhat lower rate than the country as a whole;
- FortisBC has significant heating load (in competition with natural gas), with approximately one-third of direct residential (and likely wholesale) sales for heating purposes;
- FortisBC has no rate-stabilization mechanism to dampen the effects of weather volatility;
- FortisBC competes to some extent with alternative suppliers of electric power, such as BC Hydro, given the customer choice available to wholesale and large industrial customers;
- Technological change is expected to increasingly create competitive alternatives;
- FortisBC generates 45 percent of its supply from its own hydroelectric plants, obtaining the remainder of its supply through long-term contracts and market purchases; and
- FortisBC has a power purchase incentive mechanism to mitigate its exposure to market price volatility (Exhibit B-1, Tab 5, pp. 7-13).

Ms. McShane assesses three factors associated with the regulatory component of FortisBC business risk: deferral accounts, performance-based regulation ("PBR") and depreciation expense. Ms. McShane states that, in contrast to many Canadian utilities, FortisBC has operated with few deferral accounts: it has no deferral account for short-term interest expense, it has no rate-stabilization mechanism to dampen the effects of weather volatility; and, while it has shared deviations from purchased power costs with customers, it has not operated with a pass-through mechanism for such costs (Exhibit B-1, Tab 5, p. 13).

In her discussion of the impact of FortisBC's PBR from 1996-2004, Ms. McShane notes that the Dominion Bond Rating Service ("DBRS") considers the regulatory environment in B.C. among the more progressive in Canada. In comparison to traditional cost of service ratemaking, Ms. McShane considers that the FortisBC PBR plan, which retains a link to actual costs and includes sharing, exposes the shareholder to a moderately higher level of business risk (Exhibit B-1, Tab 5, pp. 14-15).

Ms. McShane points out that the settlement agreement in the 2000 NSP included a PBR rate stabilization mechanism to limit rate increases to 5 percent or less, with a reduction in annual depreciation expense as necessary to achieve this end. In addition, the same agreement lowered the depreciation rate on transmission assets. Ms. McShane states that both factors have contributed to the free cash flow deficits currently faced by FortisBC (Exhibit B-1, Tab 5, p. 15).

Ms. McShane concludes that FortisBC faces above average business risk relative to its Canadian electric and gas peers, and relative to the low-risk benchmark utility.

Financial Risk

Ms. McShane defines financial risk as the additional risk incurred as a result of assuming debt, which results in the incurrence of additional fixed obligations that must be met before the equity investor is entitled to any of the operating income generated by the utility. Ms. McShane assesses capital structure ratios, interest coverage ratios and debt ratings as points of departure for analyzing the financial risk faced by FortisBC.

Ms. McShane calculates that the actual common equity ratio of FortisBC between 1999 and 2004 has averaged 40.1 percent. While slightly higher than the proposed 40 percent common equity ratio, it is nonetheless consistent with the maintenance of a roughly 60%/40% debt/equity capital structure for at least the last ten years (Exhibit B-1, Tab 5, pp. 16-17). Ms. McShane compares FortisBC's forecast common equity ratio to other Canadian electric utilities and concludes that it is in line with the allowed common equity ratios of other investor-owned electric utilities (Exhibit B-1, Tab 5, pp. 17-20).

Ms. McShane discusses FortisBC's interest coverage ratios as one factor that determines the level of its financial risk. Ms. McShane reports that the pre-tax interest coverage ratio in 2003 equaled 2.1 and that the average pre-tax interest coverage ratio for the five-year period ending 2003 was 2.1. Ms. McShane says that while the 2003 ratio of 2.1 is a material improvement from the ratio of 1.8 in 2002, the five-year average ratio is a deterioration from the previous five-year average ratio of 2.4 calculated over the period 1994-1998. Further, Ms. McShane offers the comparison that the 1999-2003 average ratio of 2.1 is less than the average ratio of 2.4 across other major Canadian electric utilities over the same period. Ms. McShane states that the declining interest coverage ratios of FortisBC reflect, in part, that its allowed returns on equity have generally declined more rapidly than its embedded debt costs (Exhibit B-1, Tab 5, pp. 20-21).

With respect to debt ratings, Ms. McShane reports that DBRS rates FortisBC debt BBB(high) with a "Stable" trend, and has consistently rated it such since 1996. Ms. McShane notes that this is the lowest DBRS rating of the investor-owned electric utilities in Canada. DBRS confirmed its ratings in June 2004 and provided a full evaluation of the company in November 2004. Ms. McShane summarizes the November 2004 DBRS report with the following points:

- The FortisBC financial profile has weakened in recent years due to a variety of factors including free cash flow deficits and low allowed ROEs;
- Relatively large anticipated capital expenditures over the next 4 years will contribute to large free cash flow deficits;
- The rate-stabilization mechanism on depreciation expense may keep cash flows weaker, but the projected free cash flow deficits could be reduced if this mechanism is eliminated;
- A key challenge to the financial profile remains a low interest rate environment; and
- Despite the free cash flow deficits, FortisBC's financial profile is expected to remain acceptable for the ratings.

Ms. McShane reports that the Moody's Investors Service ("Moody's") rated FortisBC Baa3 in November 2004, its first debt rating of the Company. Ms. McShane notes that the rating is premised on low business risk, a significant capital expenditure plan over the next four to five years, the need for rate increase to implement the plan, a low depreciation rate, a tight liquidity position, cash flow deficits and the need for equity infusions from the parent during the period of high capital expenditures. Ms. McShane states that a Baa3 is the lowest investment grade rating, providing little "cushion" should there be any deterioration in the business risk profile or financial parameters (Exhibit B-1, Tab 5, pp. 23-24).

Based on her assessment of FortisBC's business and financial risks, Ms. McShane concludes that a common equity ratio in the range of 40-45 percent is reasonable, compatible with its business risks and adequate to maintain a stand-alone rating of DBRS BBB(high). However, she notes that, given the forecast level of capital expenditures in the near to medium term and expected free cash flow deficits, a 40 percent common equity ratio should be regarded as the floor required to ensure adequate financing flexibility. Ms. McShane concludes that at a 40 percent common equity ratio, "FortisBC would be of higher investment risk than a benchmark Canadian utility, which requires the addition of an incremental equity risk premium to the equity return applicable to the benchmark low-risk utility" (Exhibit B-1, Tab 5, pp. 20-29).

Equity Risk Premium

As noted above, Ms. McShane accepts the Commission's ROE for a benchmark low risk utility as a point of departure for estimating the equity risk premium for FortisBC at the proposed common equity ratio of 40 percent. With this frame of reference, Ms. McShane calculates a range of equity risk premiums for FortisBC relative to a low-risk benchmark utility by estimating the risk differential as between, or as impacted by, PBR versus Cost of Service regulation, utility size, debt costs and relative costs of equity.

To assess the impact of PBR versus Cost of Service regulation, Ms. McShane utilizes a study prepared by the World Bank, which concluded that the difference between the asset (business risk) betas of energy utilities operating under rate of return regulation and price or revenue cap regulation was close to 0.40. Ms. McShane suggests that FortisBC has a risk position in the middle of the two extremes used in the World bank study, or a beta differential of 0.20. Using the Commission's market risk premium of 5.0 percent as reported in its 1999 Decision on Return on Common Equity for a Benchmark Utility, Ms. McShane concludes that the difference between PBR and Cost of Service regulation translates into a difference of 100 basis points (i.e. a 0.20 beta differential multiplied by 5 percent) (Exhibit B-1, Tab 5, p. 15).

To assess the impact of utility size, Ms. McShane utilized a study of historic returns and betas for companies of different sizes to compare the asset betas between a typical publicly-traded Canadian utility, defined by Ms. McShane as a Mid-Cap stock, and FortisBC, defined by Ms. McShane as a Low-Cap stock. Using the differential result of 0.14 and a market risk premium of 5.0 percent, Ms. McShane concludes that the size of FortisBC could justify it receiving an equity risk premium of 70 basis points (Exhibit B-1, Tab 5, p. 31).

To assess the difference between the debt costs of FortisBC and a low-risk benchmark utility, Ms. McShane assumed that a low-risk benchmark utility would be able to achieve a solid A rating on its debt. By comparing the 2002 average spread for a seven-year issue for Canadian utilities rated A(low)/A- or higher (95 basis points) to a FortisBC (Aquila(BC)) 2002 seven-year debt issue at 170 basis points above the benchmark seven-year Canada, Ms. McShane concludes that the difference in debt costs between FortisBC and a low-risk benchmark utility translates into an equity risk premium of 75 basis points (Exhibit B-1, Tab 5, pp. 32-33).

To estimate an equity risk premium for FortisBC using relative costs of equity, Ms. McShane compares the average beta of a group of A rated U.S. utilities, as proxies for the low-risk benchmark utility, to the average beta of a group of BBB rated U.S. utilities, as proxies for FortisBC. Ms. McShane concludes that the differential of 0.10 between the average betas of the two sample groups translates into an equity risk premium of 50 basis points if using a market risk premium of 5.0 percent (Exhibit B-1, Tab 5, pp. 33-35).

In sum, Ms. McShane concludes that a reasonable range for an incremental equity risk premium for FortisBC relative to the low-risk benchmark utility is in the range of 50-100 basis points, with a mid-point of 75 basis points.

2.2.2 Direct Evidence of Dr. Booth

Dr. Booth was asked by BCOAPO to provide an independent assessment of the appropriate common equity ratio and fair return for FortisBC, to assess its business risk and financial flexibility, and to make recommendations to ensure that rates are fair and reasonable. Dr. Booth indicates that his evidence is organized, in part, around: 1) a discussion of the business risk of FortisBC from a capital markets perspective, 2) a discussion of financial market access concerns and questions surrounding "rising" credit standards, and 3) a discussion about coverage ratios and how the capital market reacts to current financial metrics. The following is a brief summary of the evidence of Dr. Booth (Exhibit C5-5).

Dr. Booth considers the business risk of FortisBC to be low. Dr. Booth considers that FortisBC has little "generating" risk given that it is primarily reliant on hydroelectric generation and purchased power. Dr. Booth notes that electricity demand in FortisBC's service area is growing at a slightly higher rate than in B.C. generally, and that compared to electric utilities operating elsewhere in Canada, the regulatory regime in B.C. is stable. Dr. Booth asserts that the main impact of the FortisBC PBR is to provide an incentive to the company to operate more efficiently and earn a higher ROE, not to expose it to material risk. Further, Dr. Booth points to data on actual versus allowed ROE for FortisBC's regulated operations from 1986 through 2004 to conclude that after FortisBC moved to a PBR mechanism in 1996, the actual ROE has been above the allowed ROE (aside from 2002 when the failure to earn the allowed ROE was due to integration expenses and software write-offs). Dr. Booth notes that rather than the DBRS view that FortisBC has a consistent history of earning the regulated ROE, he would define the result rather as "over-earning." Dr. Booth sees "no reason for adding a bonus to the ROE for a system that already effectively enhances the company's ROE and does not increase its risk" (Exhibit C5-5, p. 22).

In association with his discussion of business risk, Dr. Booth provides evidence to show that he usually judges transmission operations as warranting a 30 percent common equity ratio and distribution 35 percent, while more recently, for example, the Alberta Energy and Utilities Board has awarded slightly higher common equity ratios of 33 percent and 37 percent, respectively.   In this context, and given his judgment of business risk, Dr. Booth judges the applied-for 40 percent common equity ratio as excessive.

Dr. Booth presents evidence on the degree to which FortisBC is compensated for its risk by utilizing the theoretical relationship between the risk of a firm with financial leverage to a firm without financial leverage plus a financial leverage risk premium. While recognizing that equating the effect of a higher common equity ratio and a higher allowed ROE is largely a matter of judgment, Dr. Booth determines that a higher ROE and common equity ratio awarded FortisBC (then West Kootenay Power) in a 1994 Commission decision is equivalent to 55 basis points above Terasen Gas Inc. ("Terasen Gas") (then BC Gas), the low-risk benchmark utility. Dr. Booth states that one implication of this is that it is important for the Commission to take into account all the ways that it manages the risk of FortisBC and to not double count the same risks in different areas. Dr. Booth judges that FortisBC is marginally riskier than Terasen Gas, but that this risk is more than offset by FortisBC's higher common equity ratio.

Dr. Booth comments on the debt rating implications of FortisBC being a very small electricity company issuing debt in the capital markets under its own name. Dr. Booth states that size is a factor in bond ratings, and it also affects the liquidity of the bond issue. He notes that the result is that smaller issuers tend to issue shorter term debt and have inferior bond ratings than large issuers, all else equal. Dr. Booth comments that the problems associated with the size of FortisBC, in combination with the significant growth in rate base that is anticipated as the utility refurbishes its generation, transmission and distribution plant, may pose capital market access problems. Dr. Booth notes, however, that this access problem could be mitigated with equity infusions from its parent, and ultimately recede as the rate base expansion is completed.

Dr. Booth presents some example calculations of interest coverage ratios to argue that it makes no sense to target a particular interest coverage ratio and allow a higher ROE simply because a company has a high embedded cost of debt. Dr. Booth argues that if the allowed ROE and deemed common equity ratios are considered fair, but the resulting interest coverage is considered too low because of high embedded interest costs and there are capital market access problems, then the solution is to allow or deem some preferred shares, rather than give the equity holder a bonus to the fair ROE or equity ratio.

Dr. Booth assesses the market to book ratio associated with the purchase price of Aquila(BC) by Fortis, as well as the ratios associated with other utility purchases, in comparison to a target ratio of 1.15. He notes his view that values above 1.15 indicate that the rates are too high and that the equity holders are getting a more than fair and reasonable return. Dr. Booth approximates that for the FortisBC purchase the market to book ratio based on total rate base equaled 1.38, while the market to book ratio based on equity (based on assuming debt and valuing it close to book value) equaled 1.96.

In sum, Dr. Booth asserts that the currently approved 40 percent common equity ratio and 40 basis risk premium are excessively generous. Dr. Booth is of the view that there are no grounds for increasing the generosity of these financial metrics, but rather that the elimination of the 40 basis points risk premium would be a conservative roll back.

2.2.3 Submissions

The following sections summarize various arguments and submissions of FortisBC and intervenors with respect to business risk, financial risk, and the equity risk premium.

Business Risk

FortisBC reiterates in its argument that its business risk is greater now than it has been in the past. Using Dr. Booth's frame of reference as a point of departure, FortisBC submits, with reference also to its Resource Plan, that its risk regarding its energy needs is much greater than it was in 1994; it is far more reliant on the market for energy in 2005 than it was in 1994, and the market is more volatile. FortisBC also states that it faces increasing competition from natural gas, its industrial customers have the opportunity to switch to third party supply, and residential use per customer has been steadily declining. FortisBC submits that these factors, combined with its increased reliance on a volatile market, are evidence of its increased business risk (FortisBC Argument, pp. 18-20).

BCOAPO submits that an October 2004 FortisBC presentation to DBRS (Exhibit B-4, Response to BCOAPO IR 88.1) stands in contrast to the conclusion of Ms. McShane that FortisBC faces above average business risk relative to it Canadian electric peers, and relative to the low risk benchmark utility in the B.C. context. BCOAPO submits that FortisBC has told the investment community that it is a low cost, low risk franchise with supportive regulation and no problems in accessing capital, referring in support to the following summary of the FortisBC presentation highlights provided by FortisBC in response to an information request (BCOAPO Argument, pp. 9-10):

- Vertically integrated regulated electric utility,
- Supportive regulation – a low cost, low risk franchise,
- Solid franchise history with strong economic fundamentals,
- Diversified customer base,
- 205MW low cost hydro and long term PPAs in rate base,
- Power purchase costs flow through – limited commodity risk,

- Growing regulated rate base, and
- Strong balance sheet and supportive shareholder.

Further, BCOAPO submits that comparing Ms. McShane's definition of business risk (of exposing the shareholders to the risk of under-recovery of the required return on capital) to the evidence that FortisBC's actual ROE has exceeded its allowed ROE in every year since 1996 (except 2002) would lead it to conclude that there has been no business risk attached to the operations of FortisBC (BCOAPO Argument, p. 11).

BCOAPO submits that FortisBC's industrial load has not had a significant risk impact on the Company. BCOAPO describes that there is little dependence on industrial customers when measured by revenues, and there is minimal bypass risk. Further, there is opportunity for load retention rates should such customers wish to leave the system. BCOPAO points out that no large customers have bypassed the system in the last five years, perhaps explained in part by the possibility of such customers having to reimburse FortisBC for stranded assets should they choose to buy supplies elsewhere (BCOAPO Argument, pp. 12-14). BCOAPO also submits that "what holds in the face of bypass risk also holds in an absolute sense: FortisBC's reliance on low cost hydro makes its generation risk minimal. In practice there is minimal risk of the power not being dispatched or the assets being stranded" (BCOAPO Argument, p. 19).

BCOAPO submits that the risk associated with residential load is limited. In particular, it submits that FortisBC has incremental residential heating load to begin with because its rate are competitive due to its low generating cost. Further, BCOAPO says that the Company has not requested any weather normalizing rate stabilization mechanism in the past ten years. It submits therefore that the company does not consider the impact of weather volatility on residential load to be a material risk (BCOAPO Argument, pp. 12-13).

In regard to the risk associated with market purchases and market volatility, KOECA submits that it is unlikely that higher power purchase costs in the future will result in reduced returns for shareholders given its expectation that the Commission will ensure that this risk will be passed on to customers to keep the Company healthy. Further, KOECA submits that FortisBC does not address how separate risk factors may partially negate themselves, pointing out in example that a decline in residential use per customer, if it leads to a reduction in total residential demand, "would partially compensate for the supposed risk associated with power purchases" (KOECA Argument, pp. 4-5). KOECA submits that if there is uncertainty about the correct methodology to apply to an evaluation of FortisBC's risk, it makes sense to seek "ground truth" by paying attention to the actual experience of the company (KOECA Argument, p. 5).

Financial Risk

FortisBC argues that its financial risk is greater than it has been in the past. Noting again that the financial risk of a utility can be captured in its capital structure ratios, interest coverage ratios and debt ratings, FortisBC reiterates that its 1999-2003 pre-tax interest coverage ratio of 2.1 is significantly less than the previous 5 year average of 2.4 observed between 1994 and 1998. Further, it notes that its debt rating was downgraded by DBRS in 1996 to BBB(high), lower than any other Canadian electric utility in the sample provided by Ms. McShane in her evidence (FortisBC Argument, pp. 21-22), and its Moody's debt rating is Baa3 is lower still, equivalent to a DBRS rating of BBB(low).

FortisBC argues that Dr. Booth's interest coverage ratio calculations, and the conclusions that he draws from them, are flawed and inaccurate. FortisBC submits therefore that this evidence should be rejected (FortisBC Argument, pp. 22-26). FortisBC submits that it was unable to access 30-year bonds in 2004, substantially due to its low interest coverages and being regarded as too high risk (FortisBC Argument, pp. 22, 25-26).

BCOAPO notes that Dr. Booth indicated in cross-examination by FortisBC Counsel that he accepts the interest coverage ratios calculated by FortisBC. However, BCOAPO quotes Dr. Booth as noting that the interest coverage ratios are all temporary timing phenomenon, "basically waiting until the debt costs roll out and wait until its capital expenditure program is completed" (BCOAPO Argument, p. 22).

BCOAPO comments on the cross-examination by Commission Counsel of both Ms. McShane and Dr. Booth as to the impact of an increase in the equity risk premium from 40 to 75 basis points on the five credit challenges identified by Moody's in its November 2004 report. Those five credit challenges are a $450 million capital expenditure plan over next 5-years, rate increases to support the capital expenditure plan, relatively low depreciation rates, a tight liquidity position, and free cash flow deficits requiring equity infusions from its parent. BCOAPO submits that the testimony as to the marginal or non-existent impact of an increase in the equity risk premium on these credit challenges further undermines FortisBC's case for an increase in the equity risk premium (BCOAPO Argument, p. 21).

FortisBC proposes to maintain its current capital structure, with a common equity ratio of 40 percent, noting that the BCOAPO expert also recommends a common equity ratio of 40 percent. Further, FortisBC notes that in their written arguments, intervenors either endorsed this capital structure or had no comment. FortisBC submits that the supporting evidence and the absence of argument against the proposed capital structure strongly support an Order of the Commission approving a capital structure which includes a common equity ratio of 40 percent (FortisBC Argument, p. 17; FortisBC Reply Argument, p. 4).

Equity Risk Premium

BCOAPO presents argument that questions the relevance and justification of Ms. McShane's analysis of the appropriate equity risk premium for FortisBC relative to the low-risk benchmark utility. BCOAPO asserts that Terasen Gas is the BCUC low risk utility given its 33 percent common equity ratio and the fact that it is not granted an equity risk premium above the BCUC automatic ROE. The BCOAPO argues that Ms. McShane refused to accept that Terasen Gas is the BCUC low risk benchmark utility (BCOAPO Argument, p. 16). BCOAPO comments that financial risk compounds business risk and a low common equity ratio indicates low business risk. BCOAPO questions that if Terasen Gas is not the low risk benchmark then it is reasonable to ask what the proposed 75 basis points equity risk premium is over. To illustrate this point, BCOAPO suggests that it may be, for example, that Terasen Gas and FortisBC are now of equivalent risk in which case there would be no reason for a risk premium for FortisBC over the Commission's low risk benchmark (BCOAPO Argument, pp. 16-17).

BCOAPO expands upon its argument in this matter by commenting on the DBRS BBB(high) debt rating of Fortis (which Ms. McShane equates with a Standard & Poors (S&P) rating of BBB) relative to the debt rating of a low-risk benchmark (which Ms. McShane equates with an A rating). BCOAPO submits that Ms. McShane's methodology of assessing the differentials between A and BBB rated utilities is flawed, in part because it does not account for the impact of FortisBC's size on its debt rating (and the related matter that spreads may include liquidity premiums for smaller issues). BCOAPO submits that "if FortisBC were simply a larger firm its bond rating would be higher even if its business risk is unchanged, so basing the analysis on bond ratings in part simply awards FortisBC a higher ROE simply because it is small." BCOAPO submits further that Terasen Gas, with its DBRS A and S&P BBB debt ratings, could fit within the same rating group as FortisBC in Ms. McShane's analysis (BCOAPO Argument, pp. 17-18).

FortisBC submits that FortisBC and Terasen Gas cannot be regarded as having similar debt ratings, as suggested by BCOAPO, in part because: 1) BCOAPO is proceeding on the incorrect premise that Terasen Gas is equivalent to a low risk benchmark utility, when Ms. McShane states that a low risk benchmark utility would be an A rated utility, which Terasen Gas is not; and 2) FortisBC has two ratings in the BBB category and is therefore rated lower than Terasen Gas (FortisBC Reply Argument, pp. 10-11).

With respect to utility size, FortisBC replies that it remains a small utility, unable to diversify its risks to the same extent as larger utilities whose assets, geography and economic bases are less concentrated (FortisBC Reply Argument, p. 12).

In its argument, IMEU submits that FortisBC acquired the utility approximately one-year ago understanding the risks and rewards of its investment. It is of the view that the purchase price that was struck, for a significant premium over book value, was based on this understanding. Therefore, IMEU submits that an increased risk premium is inappropriate and not justified in the short-term, a conclusion it states is also supported by the evidence on FortisBC's risk factors (IMEU Argument, pp. 5-12).

BCOAPO states that with a 40 percent common equity ratio Fortis paid about $734 million to acquire $377 million in equity earning the Commission's automatic ROE plus 40 basis points, which results in a ratio of almost twice book value. BCOAPO submits that this is an excessive, unfair market to book ratio, and that the correct regulatory response should be to reduce the premium, not increase it to 75 basis points (BCOAPO Argument, p. 21).

In response to the issue of the premium over book value, FortisBC submits that the price to regulated book value on its purchase (1.8) reflects also the amount paid for the majority of regulated assets/companies sold in Canada over the last 7 years. Further, it submits that because it is required to engage upon an extensive capital expenditure program over the next several years the premium it paid will effectively be reduced (FortisBC Reply Argument, p. 15).

FortisBC submits that the debt market problem and fair return on equity are not independent from each other because capital structure and ROE (as a function of business risk profile) factor into the willingness of the bond market to lend funds under reasonable rates and terms. FortisBC submits that an increase in the equity risk premium that is fully compensatory with its business and financial risks, along with an increase in the depreciation rate, will address the Company's inability to access the long-term bond markets (FortisBC Reply Argument, p. 14).

2.2.4 Commission Panel Determinations

The Commission Panel has considered the evidence of FortisBC and BCOAPO, and the arguments of all parties. The following discussion highlights the Commission Panel's observations and conclusions in this regard.

With respect to market demand components of business risk, the Commission Panel believes that the prospects for FortisBC residential demand are good given the strong growth prospects in the Okanagan service area, in spite of the penetration of natural gas for heating new residential construction. The Commission Panel is persuaded by the argument that residential heating demand is incremental and not a significant business risk as FortisBC defines it. The Commission Panel notes that because FortisBC is a capacity constrained utility, a reduction to the heating component of demand could actually serve to reduce its business risk. Yet, to the extent the penetration of natural gas for heating could be regarded as a material risk, and to the extent that such risk could have a detrimental impact on FortisBC's credit rating, an increase in the equity risk premium would serve to increase this risk all else equal. The Commission Panel does not agree that a reduction in residential use per customer (as one factor of total demand) is an indication of a net increase in business risk for FortisBC, particularly in light of increasing load growth in the FortisBC service area generally. The Commission Panel also agrees with the evidence that suggests, in general, that population and economic growth will remain strong in the FortisBC service area.

With respect to supply risk factors, the Commission Panel acknowledges that FortisBC does compete to some extent with alternative suppliers of electricity given the customer choice available to wholesale and large industrial customers. The Commission Panel notes, however, that there are strong constraints on the likelihood of municipalities opting for alternative suppliers, and that the industrial component of load is not large and also unlikely to opt for alternative suppliers. The evidence and argument bear this out. Further, the Commission Panel acknowledges that there is risk associated with market purchases and market volatility, but it does not agree that this risk has increased to any measurable extent for FortisBC. FortisBC obtains low-cost supply from its own generating plants and long term contracts, with the remainder of its supply obtained through market purchases. Market purchases, while an increased share, are still limited, and FortisBC has a power purchase incentive mechanism to mitigate its exposure to market price volatility.

The Commission Panel agrees with the evidence that characterizes the regulatory environment in B.C. as progressive, believing it as well to be a positive consideration in respect of the regulatory risk that FortisBC faces. The Commission Panel observes that the progressive regulatory environment in B.C. is noted as a strength in the DBRS credit rating evaluation of FortisBC. The Commission Panel does not agree with the view that the FortisBC's PBR plan is inherently more risky than a traditional cost of service regulatory framework, particularly given the various sharing mechanisms that are components of this plan and the demonstrable evidence that FortisBC's actual ROE has, with one exception, met or exceeded its approved ROE since 1996. The Commission Panel does not consider the evidence of actual ROEs consistently exceeding allowed ROEs to imply, in and of itself, any conclusion about changes in the level of business risk, higher or lower. Even so, the Commission Panel considers the question of whether a utility has been able to meet its revenue requirements as a useful test of the reasonableness of an allowed ROE. In the period since 1994 FortisBC has with one exception met or exceeded its revenue requirements.

FortisBC emphasizes its interest coverage ratios, arguing in part that current low interest coverages are a substantial cause of its inability to access the 30-year bond market in 2004, and in turn that this circumstance is the main driver of its application for an increase in its equity risk premium. FortisBC argues that its interest coverages are significantly lower than in the past by comparing its average interest coverage ratio of 2.1 over the five-year period, 1999-2003, to its average interest coverage of 2.4 over the previous five-year period, 1994-1998. The Commission Panel finds that this comparison is not substantively informative. While Ms. McShane states that the decline reflects, in part, that allowed ROEs have generally declined more rapidly than the embedded debt costs, neither she nor FortisBC have provided any other detailed rationale or context to explain the differences between the two five-year periods. The Commission Panel observes that the consistent DBRS rating of BBB(high)-Stable trend since 1996 largely spans both of the five-year periods used in the averaging calculations. Further, the Commission Panel notes that FortisBC's actual 2004 pre-tax interest coverage ratio is 2.32 and its average pre-tax interest coverage ratio for the period 2000 to 2004 is 2.16, both of which represent increases, respectively, from its 2003 ratio of 2.1 and its 1999-2003 average ratio of 2.1 (Exhibit B-12, Response to BCUC IR 12.5). FortisBC has not explained how these increases should be interpreted in the context of the evidence of decreases that it presents in evidence and in argument. FortisBC notes that the difference between the average interest coverage ratios of the two five-year periods is significant, a difference equal to 0.3. The Commission Panel notes that in FortisBC's initial 2005 application the estimated interest coverage ratio is 2.06, and declined to 2.01 on the basis of assuming a 40 rather than 75 basis points risk premium (Exhibit B-12, Response to BCUC IR 12.7). The difference of 0.05 between these two ratios could be regarded in this context as less than significant and relatively insensitive to changes in the equity risk premium. In addition, the Commission Panel agrees that low interest coverages could be considered a temporary phenomenon in light of FortisBC's planned capital expenditures over the next four years and low depreciation rates currently. The Commission Panel believes that, even to the extent that FortisBC's interest coverages could be regarded as too low, declining, or more than a temporary phenomenon, an increase in the equity risk premium is not the appropriate means to first consider for improving FortisBC's interest coverages. The following discussion elaborates on this.

BCOAPO referred in argument to cross-examination of both Ms. McShane and Dr. Booth by Commission Counsel as to the expected impact of an increase in the equity risk premium on each of the five credit rating challenges identified by Moody's in its November 2004 report. Those credit rating challenges are (Exhibit B-12, Response to BCUC IR 15.0):

- A significant $450 million capital expenditure plan to be implemented over the next 4-5 years;
- The possible need for rate increases in each of the next few years to implement the capital expenditure plan;
- A relatively low depreciation rate for rate-making purposes;

- A liquidity position that is tight for a Baa3 utility company; and
- Free cash flow that is expected to be negative for the next few years, necessitating equity infusions from its parent, as well as additional debt issuance.

The Commission Panel is of the view that both experts' testimony as to the limited or non-existent impact of an increase in the equity risk premium on these credit challenges diminishes the FortisBC argument that an increase in the equity risk premium will materially affect its credit rating and its ability to access the long-term bond market. FortisBC acknowledges in response to a Commission information request that while a change in its equity risk premium from 40 to 75 basis would be a positive consideration, it alone would not likely result in an increase in FortisBC's credit rating. In their November 2004 credit rating reports, both DBRS and Moody's emphasize the issues of FortisBC's free cash flow deficits and low depreciation rates. DBRS notes in one instance that higher depreciation rates could reduce FortisBC free cash flow deficits. The Commission Panel observes that DBRS maintained its FortisBC debt rating of BBB(high)-Stable trend despite its concerns.

The Commission Panel believes that it would be untimely and inappropriate to increase the equity risk premium in response to the credit challenges noted above without measures being taken to more directly address these credit challenges, particularly in light of the Commission Panel's views as to the business risk of FortisBC. To this end, and in alignment with the November 2004 evaluations of both DBRS and Moody's, the Commission Panel has directed FortisBC in this Decision to file its forthcoming study of depreciation rates with its next revenue requirements application, and to have the new rates form part of that application. Also, the Commission Panel notes that the rate stabilization mechanism on depreciation expense is no longer in effect.

The Commission Panel has concerns about the methodology used by Ms. McShane to determine an incremental equity risk premium for FortisBC. For example, the Commission has determined that Terasen Gas is a low risk benchmark utility in B.C., and to ignore this as a reasonable proxy in the analysis calls into question the entire framework, particularly in light of the reliance, in part, on utilities based in the US as proxies for the low-risk benchmark. Further, the Commission Panel agrees with the BCOAPO submission in regard to the impact of size on credit ratings, which calls into question the methodology of comparing the credit ratings across utilities as a means to determine an incremental risk premium, without controlling for the impact of size.

The Commission Panel notes that a fundamental test of the appropriateness of an allowed ROE is whether the utility has been able to attract equity capital. Evidence of this test has been met: the willingness of FortisBC to purchase the equity of Aquila(BC) and to pay a premium in so doing.

The Commission Panel approves the FortisBC application to maintain a common equity ratio of 40 percent and denies the FortisBC application to increase its equity risk premium from 40 to 75 basis points. The Commission Panel denies the BCOAPO recommendation to reduce FortisBC's equity risk premium from 40 basis points to zero on the basis that there is insufficient evidence in support of this recommendation.

2.3 2005 Revenue Requirements

2.3.1 Rate Base

A utility's rate base represents the net investment in assets necessary to provide service. FortisBC's Rate Base, as described in Exhibit B-1 at Tab 6, is comprised principally of Plant in Service, Accumulated Depreciation and Amortization, Deferred Charges and Credits, Allowance for Working Capital, and an Adjustment for Capital Expenditures (FortisBC Argument, p. 29).

FortisBC submits that its forecast mid-year rate base for 2005 of $598,105,000, as provided in Schedule 1 to the Third Revised Application (Exhibit B-26), be approved for purposes of establishing 2005 Revenue Requirements and setting rates to customers effective January 1, 2005 (FortisBC Argument, p. 30).

Rate Base costs include such items as cost of debt, cost of equity, income taxes, property and capital taxes, depreciation and amortization and Allowance for Funds Used During Construction ("AFUDC"). FortisBC seeks approval of forecast total Rate Base costs of $78,569,000 (Exhibit B-26, p.3; FortisBC Argument, pp. 31-38).

Commission Panel Determinations

The Commission Panel accepts the proposed mid-year rate base of $598,105,000 for 2005 subject to directions contained in this Decision that affect the components of rate base. Likewise, FortisBC should update its forecast Rate Base costs according to the relevant Commission Panel determinations elsewhere in this Decision.

2.3.2 Power Supply

The Commission Panel approves FortisBC's forecast Power Supply costs for 2005 of $71,010,000. This is discussed in Section 2.1.2: Power Purchase and Wheeling Forecast.

2.3.3 Operations and Maintenance Expenses and Capitalized Overheads

Forecast 2005 Operations and Maintenance ("O&M") Expenses, before and after capitalized overheads, increased significantly over the 2004 target levels that were part of the 2004 Negotiated Settlement Agreement approved by Order No. G-38-04. The following comparative schedule appears on page 1 of Exhibit B-66 and provides an overview and high level explanations of the major drivers for the increase.

	2004 Targeted O&M	2005 Forecast O&M	Increase/ (Decrease) over Targeted 2004 O&M	Increase due to Transition Plan	Increase due to Inflation	Other Increases
Total before capitalized overheads	$35,645,000	$39,569,000	$3,924,000	$1,158,000	$1,150,000	$1,616,000
Capitalized Overheads	($2,800,000)	($3,396,000)	($596,000)			
Total net of capitalized overheads	$32,845,000	$36,173,000	$3,328,000			

Of the total increase of $3,924,000, the portion caused by the Transition Plan activities, i.e. $1,158,000, is discussed in greater detail in Section 2.6, Transition Plan.

FortisBC states that the inflationary increase of $1,150,000 is the result of normal inflationary pressures on labour, materials and other costs. FortisBC indicates that of this amount, $500,000 is due to increases in benefits costs relating to medical, dental and vacation entitlements, $350,000 is due to wage increases for management and bargaining unit employees, averaging 2.5% to 3%, and $300,000 is the effect of non-labour inflation (i.e. 2%) on the 2005 budget (Exhibit B-66, pp. 1-2).

The amount of $1.6 million, identified as 'Other Increases', arises from additional activities planned in functional areas such as generation, transmission and distribution, and administration and general. The $1.6 million increase actually represents a net amount, which is comprised of various cost increases totaling $2.8 million that are offset by a $1.2 million decrease in insurance and vehicle lease costs. A significant portion (i.e. $1.6 million) of the 2.8 million cost increase is forecast to be spent in the transmission and distribution functional area. Increased activity for substation O&M, and transmission and distribution line maintenance is the major driver for the increase in this functional area and comprises $1.1 million of the $1.6 million. A further $850,000 of the total increase of $2.8 million is due to increased activity in internal audit and corporate governance and environmental, health and safety (Exhibit B-66. pp.2-5).

The increase in the amount of capitalized overheads is a direct function of capital activity, which increased for 2005.

Submissions

BCOAPO states that: "[they] are not in a position to review in detail the OM&A expenditures of the utility" (BCOAPO Argument, p. 25). Mr. Wait argues that the increase in the transmission and distribution expenses for 2005 appears to be excessive (Wait Argument, p.3). IMEU states: "[it] is also concerned that the impact of PBR settlements in past years has resulted in a loading up of costs which are being picked up in the 2005 Revenue Requirements for the Company" (IMEU Argument, p.18). IMEU asks the Commission to review closely the appropriateness of these significant increases through rebasing (IMEU Argument, p. 4).

FortisBC states that the Company has repeatedly expressed its position that base O&M targets have been too low and hence inappropriate on a go forward basis. The Company submits that a material portion of the proposed increase in O&M Expense for 2005 reflects FortisBC's reassessment of the overall level of O&M expense required to meet service obligations to its customers in the areas of customer service, transmission and distribution, and administration and general costs (FortisBC Argument, pp. 40-41).

Commission Panel Determinations

The Commission Panel has considered all the evidence and arguments and concludes that the proposed increases in forecast 2005 O&M Expenses, before overheads capitalized, over the approved 2004 target levels, appear to be reasonable and required. The Commission Panel fully supports FortisBC's strategic goals and specific objectives to meet and improve service obligations in various areas and in particular the areas of customer service and transmission and distribution (refer to Section 2.7 for a comprehensive discussion of customer service). The Commission Panel believes that FortisBC should be provided with the resources to allow it to achieve these goals and objectives. The inflationary increases of $1,150,000 are largely uncontrollable by the Company in the short term.

The Commission Panel approves for FortisBC the forecast 2005 O&M expenses, before capitalized overheads, of $39,569,000, subject to adjustments discussed elsewhere in this Decision. It is important to note that specific directives, as set out in Section 2.4.2 on the Operating Expense incentive mechanism, form an integral part of the approval for the above level of expenses. To be clear, the incentive mechanisms are designed to ensure that approved resources are in fact spent on planned programs and activities in 2005.

2.3.4 Pensions

FortisBC has three pension plans: the IBEW Pension Plan, the COPE Pension Plan, and the Fortis Retirement Income Plan ("FRIP"). The IBEW and COPE Pension Plans are defined benefit pension plans. The FRIP consists of a defined benefit provision and a defined contribution provision. Additionally, the Company also has a supplemental pension plan. At the end of 2004 the Pension Plan Funded status was a plan deficit of approximately $23 million (Exhibit B-12, BCUC IR 73.0).

The Company records its annual pension benefits costs on an accrual basis in accordance with the recommendations of CICA Handbook Section 3461 (Exhibit B-12; BCUC IR 73.1.1). The Company estimates the forecast 2005 pension expense to be $3,860,000 and pension funding to be $4,560,000; in 2005 funding will exceed expense by $700,000 (Exhibit B-80, p. 1). In general, the amount of pension expense and the amount of annual funding to the pension plans by the Company will not match in a given year. The difference between these two amounts is recorded as an increase or decrease in the Prepaid Pension Costs account in deferred charges (Exhibit B-12, BCUC IR 34.8). The additional $700,000 in excess of funding for 2005 results in a year end 2005 balance of $5,948,000 for deferred Prepaid Pension Costs account (Exhibit B-80, p. 1).

Commission Counsel questioned Mr. Meyers concerning the different pension costs reported in response to BCUC IR 34.8 and 73.4. Mr. Meyers explained that BCUC IR 73.4 reflected the updated actual year end financial statements for 2004. Also, Mr. Meyers acknowledged that the difference, which impacts 2005, is reflected in the revised applications (T5: 882).

Commission Panel Determinations

The Commission Panel accepts the Company's forecast 2005 pension expense, pension funding amount, and the Prepaid Pension Costs account balance of $5,948,000 at year-end 2005.

2.3.5 Other Post-retirement Benefits

Other post-retirement benefits are benefits to employees for extended health, group MSP, and life insurance. Generally Accepted Accounting Principles ("GAAP") require that all forms of post-retirement benefits be accounted for on an accrual basis as recommended in CICA Handbook Section 3461. The Company records its annual other post-retirement benefits costs on a cash basis, which is not in accordance with CICA Handbook

Section 3461. In the negotiated settlement for the 2000-2002 Revenue Requirements the parties agreed to a variance from GAAP to allow post-retirement benefits to be recorded on a cash basis. The negotiated settlement was approved by Commission Order No. G-134-99 (Exhibit B-12, BCUC IR 73.1-73.2).

For 2005 the Company proposes that the cash basis of accounting for other post-retirement benefits continue (Exhibit B-12, BCUC IR 73.1.2). Mr. Meyers explained in his testimony that the variance from GAAP was appropriate since the Company is required to fund pension expense, but not other post-retirement benefits. Also, the Company does not pay out cash for the other post-retirement benefits like it does for pension expense (T5: 884-886).

The Company estimates an expense of approximately $300,000 using the cash basis. If CICA Handbook Section 3461 were applied, the accrued expense would be $1,380,000. However, if the Company were to adopt the accrual basis prospectively beginning in 2005, the accumulated liability of $4,400,000 would also need to be amortized into expense. Amortization of the accumulated liability of $4,400,000 over approximately 14 years, based on the Expected Average Remaining Service Lifetime of the covered group, results in an additional annual amortization of about $320,000. In total the Company expects the total 2005 other post-retirement expense to be approximately $1,700,000 ($1,380,000 + $320,000) if Section 3461 were adopted. However, if the current variance from GAAP were continued, the Company estimates the accumulated liability to be $5,500,000 at December 31, 2005 (Exhibit B-12, BCUC IR 73.1.3).

Commission Panel Determinations

The Commission Panel notes that the other post-retirement benefits earned each year that were not expensed have already accumulated into a large future liability that continues to increase. However, full compliance and adoption of Section 3461 of the CICA Handbook in 2005 would result in a large rate increase. **The Commission Panel denies the request to continue to record other post-retirement benefits on a cash basis. The Commission Panel orders a variance from GAAP to require that the transition from the cash basis to accrual accounting for other post-retirement benefits be phased-in over a three-year period. For 2005 the Company will include in expense the current cost under the cash basis plus one-third of the accrued expense as if it were in full compliance with Section 3461 and the change were adopted prospectively beginning in 2005. Subsequently for 2006, the Company will include in expense the cost under the cash basis plus one-half of the accrued expense as if it were in full compliance. In the final transition year for 2007, the Company will include the full accrued expense and be in full compliance with Section 3461 of the CICA Handbook. In calculating the Company's 2005 and future revenue requirements, the portion of other post-retirement benefits expense not expected to be paid-out in cash is to be credited to rate base.**

2.3.6 Employee Stock Option Expense

The Company's stated in its response to BCUC IR 74.0 that the Company has not included employee stock option expense in the utility financial schedules in 2005 or in any other year. It also stated that all stock option expenses have been and will be borne by the parent company. However, on March 18, 2005 the Company filed a List of Errata. The Errata indicated that the previous response to BCUC IR 74.0 was in error. The Errata stated that the utility financial schedules contain $25,000 of employee stock option expense in 2004 and $40,000 in 2005 (Exhibit B-24, List of Errata: Item 4).

Commission Counsel questioned Mr. Meyers if the $40,000 in employee stock option expense was still in the application. Mr. Meyers stated that the expense was still in the application and was not aware of previous Commission decisions disallowing employee stock option expense (T5: 889-890). The Commission has disallowed employee stock option expense in the BC Gas Utility Ltd. 2003 Revenue Requirements Decision (p. 15) and in the Pacific Northern Gas Ltd. 2004 Revenue Requirements Decision (p. 47).

Commission Panel Determinations

The Commission Panel directs that the $40,000 employee stock option expense and its related tax effect be removed from the 2005 Revenue Requirements.

2.3.7 2004 Incentive Sharing Adjustments

Commission Order No. G-20-05 approved the 2004 Incentive Adjustments as based on preliminary 2004 financial results, for a total credit of $2,175,000. The Incentive Adjustments comprised a combination of operating, power purchase and DSM incentives. This credit amount is shared between customers and shareholders in accordance with the sharing formulas agreed to in the 2004 Negotiated Settlement Agreement. The customers' share is $1,469,000, which is carried forward and serves to reduce the 2005 Revenue Requirements. The remainder of $706,000 is to the shareholders' account.

FortisBC's Second Revised Application increased the approved customer share of the 2004 Incentive Adjustments from $1,469,000 to $1,791,000. The final total 2004 Incentive Adjustments are based on actual information contained in the audited 2004 financial statements.

Commission Panel Determinations

Further to the approval granted in Commission Order No. G-20-05, the Commission Panel approves the final net 2004 Incentive Adjustments of $1,791,000. This credit balance is to be carried forward and included in the determination of the 2005 Revenue Requirements.

2.4 2005 Incentive Sharing Mechanisms

2.4.1 DSM and Power Purchase Incentives and Flow-through Costs

FortisBC proposes to retain certain aspects of the existing sharing mechanisms for 2005. The Company states: "The Power Purchase Incentive and the Demand Side Management Incentive Mechanisms have been shown to be effective and desirable to customers and the Company. No changes are proposed to either mechanism for 2005." (Exhibit B-1, Tab 8, p. 30)

FortisBC is of the view that the DSM incentive has increased the Company's focus on meeting and exceeding the energy efficiency targets and therefore it proposes to retain the existing DSM incentive for 2005 (FortisBC Argument, p. 48). Further detail and submissions on the DSM Incentive Mechanism are summarized Section 2.5: 2005 Demand Side Management Expenditure Plan.

The Company also proposes to retain the existing power purchase incentive mechanism, under which (a) the full advantage of cost savings either currently embedded in contracts, or which are anticipated, are included in the Power Purchase Forecast, and are therefore to the full benefit of customers, and (b) variances, other than load variances, from the Revenue Requirements forecast are applied 65 percent to customer rates in the subsequent year (75 percent for variances in excess of $1,000,000) (FortisBC Argument, p. 49).

Furthermore, FortisBC proposes the continuation of flow-through treatment (i.e. customers assume 100% of the risk and benefit of variances between approved and actual amounts) for certain other costs over which it has limited or no control. Specifically, these costs are the differences between forecast and actual property taxes, provincial water fees, and the Power Purchase expense related to the Brilliant contracts for 2005. In addition to the continued flow-through treatment for the above items, FortisBC proposes to add a new flow-through item that seeks flow-through treatment for the costs of capacity block power purchases forecast for November and December 2005 (FortisBC Argument, p. 50).

Intervenors did not specifically comment on these Incentive Mechanisms and Flow-Through Costs.

Commission Panel Determinations

The Commission Panel approves the continuation of the existing Power Purchase Incentive and the DSM Incentive Mechanisms for 2005. The Commission Panel also approves for 2005 the continuation of the above proposed flow-through cost items as well as the flow-through for the costs of capacity block power purchases forecast for November and December 2005. In addition, the Commission Panel directs FortisBC to treat income taxes and the expensed portion of Cost of Debt as flow-through cost items in 2005.

2.4.2 Operating Expense Incentive

FortisBC is proposing a temporary asymmetrical sharing mechanism for 2005 with respect to O&M expenses. The Company states that: " Under this proposal, to the extent that 2005 O&M Expense, net of capitalized overheads, are lower than the forecast O&M Expense of $36,173,000 (Exhibit B-26), the variance will be shared equally with customers. Actual O&M Expense in excess of the forecast O&M Expense of $36,173,000 will be entirely to the account of the shareholder." (FortisBC Argument, p.50)

Submissions

NRI was initially concerned that FortisBC was still proposing a modified form of PBR for O&M for 2005. NRI goes on to state however, that: "On further consideration, we don't think that this is a significant issue." (NRI Argument, p. 2).

BCOAPO agrees with the general approach proposed by FortisBC with respect to the 2005 sharing mechanism (BCOAPO Argument, p. 7).

KOECA addressed the issue of PBR and the incentive mechanism extensively, during cross examination and in their Final Argument. KOECA states that it protested the inception of the previous PBR scheme because it believed it had serious flaws. KOECA goes on to point out that: "…there never has been a stated rationale for 50-50 sharing between the utility shareholders and the customers" and it submits that 50-50 sharing for cost savings is so rich for the company that it is compelled to cut services until there is a negative reaction (KOECA Argument, p. 3). KOECA states that: "The incentive system must be constructed so that there is little or no incentive for undesirable activity." (KOECA Argument, p. 3) It asks that the Commission set up a process immediately to determine what sharing ratio should appropriately be set for any incentive mechanism the company is allowed to use, from now on. It goes on to ask that in the meantime the Commission rule that a sharing ratio of 90-10 (in favour of the customers) be instituted (KOECA Argument, p. 4).

FortisBC argues that BCOAPO, IMEU, and KOECA are in effect seeking to re-write the rules of PBR long after the rules were agreed to by customers and the utility, after the results of each year have been finalized, and after the monies have long since been disbursed to the shareholder and customers. FortisBC also states that it is difficult to conceive of how the Commission could, by reducing the monies approved for O&M force FortisBC's shareholders to pay for improvements to customer service. Any forced cuts will only end up hurting customers. FortisBC encourages customers and the Commission to focus on the results of the utility's programs as reflected in objective measures of customer service levels (FortisBC Reply Argument, p. 19).

Commission Panel Determinations

The Commission Panel reviewed and considered the evidence on the proposed asymmetrical operating expense incentive mechanism. While the Commission Panel supports the concept of a sharing mechanism with respect to O &M Expenses in general, it does not agree that sharing should start with the "first dollar". The Commission Panel is of the view that it is management's normal responsibility to try to achieve a reasonable level of saving over budget amounts.

In the current circumstances, it is the Commission Panel's view that it is important to maintain a fair balance in terms of risk sharing between customers and shareholders, and that this generally implies sharing should occur for both positive and negative O&M expense variances.

The Commission Panel is of the strong opinion that only the cost savings from true productivity/efficiency improvements in business processes and procedures should be subject to sharing and that cost savings generated through deferral or cancellation of planned activities are not acceptable for sharing. The Commission Panel is confident that the Company will produce savings from productivity/efficiency improvements inasmuch as Mr. Hughes, President and CEO, testified that FortisBC is very focused on productivity and the management of operations and maintenance costs (T2:77).

Finally, the Commission Panel firmly believes that a very strong link needs to exist between the granting of O&M expense incentives to shareholders and the achievement of objective and measurable performance targets by the Company. **Consequently**, **the Commission Panel directs FortisBC to establish for 2005, an operating expense incentive mechanism with the following parameters:**

(a) The total variance for consideration will be calculated as the difference between the forecast 2005 O&M expenses, net of capitalized overheads, and the actual 2005 O&M expenses, net of capitalized overheads;

(b) **Favourable variances, which result from the deferral or cancellation of planned activities/programs and/or reductions to existing service levels, will not be eligible for the sharing mechanism. FortisBC is directed to record these type of favourable variances in a deferral account, whose disposition will be dealt with by the Commission at a future date;**

(c) **The initial $500,000 of a positive or negative variance [as determined by the conditions set out in (a) and (b)] will be shared on a flow-through basis, i.e. 100% to the customer's account;**

(d) **Both positive and negative variances in excess of the $500,000 "deadband" in (c) will be subject to sharing. The sharing ratio will be 60:40 to shareholders and customers, respectively;**

(e) **The sharing of an eligible favourable O&M expense variance in (d) will also be subject to the satisfactory achievement of FortisBC's performance targets (see following paragraph (f) for a detailed discussion). If the Company experiences an unsatisfactory result in any one or more performance targets, the Commission will determine at the 2005 Annual Review whether to disqualify FortisBC from sharing in an eligible favourable operating expense variance in 2005. The Commission will apply a high standard of review, as necessary; and**

(f) **In reference to (e) above, the Commission Panel further directs that within 60 days of this Decision, FortisBC is to file with the Commission, for review and approval, objective and measurable performance metrics and specific targets to be achieved in 2005. These performance metrics should be appropriate for the measurement of actual performance in the generation, transmission, distribution, and customer service functions of the Company (Commission Panel determinations with respect to Customer Service are set out in Section 2.7). For example, SAIDI, CAIDI could be considered appropriate performance metrics for certain functions.**

The following example (assuming a favourable variance) will serve to demonstrate the functioning of the above operating expense incentive mechanism.

Forecast 2005 O&M Expenses, net of capitalized overheads	$36,173,000 [1]	Exhibit B-66, p.1
Assumed actual 2005 O&M Expenses, net of capitalized overheads	35,104,000	
Gross Variance	1,069,000	Favourable
Less: Assumed favourable variance due to deferral of planned activity	200,000	to deferral account
Net Variance	869,000	Favourable
Less: $500,000 “Deadband”- 100% to customers	500,000	
Variance eligible for sharing	369,000	Favourable
Shareholder’s share @ 60%	221,400	
Customer’s share @ 40 %	147,600	

In the above example calculation, customers would effectively “recapture” $847,600 of the total favourable variance of $1,069,000.

2.4.3 Review of PBR

FortisBC intends to complete a comprehensive review of PBR with a view to engaging in stakeholder consultations by the fourth quarter of 2005. FortisBC says that it will propose implementation in 2006 at the earliest if a fair and workable mechanism can be determined (FortisBC Argument, p. 51).

KOECA argues that a PBR must be reviewed thoroughly, with all necessary evidence brought forward in an oral public hearing to determine whether PBR should be continued at all (KOECA Argument, p. 4). BCOAPO supports FortisBC’s proposal for stakeholder consultation, but believes it should be primarily aimed at identifying issues of concern and points of disagreement between all parties involved. BCOAPO submits that this should help establish a more focused and efficient Commission process for review of FortisBC’s PBR mechanism (BCOAPO Argument, p. 7).

Commission Panel Determinations

The Commission Panel agrees with FortisBC’s intentions and timeline to engage in stakeholder consultations to review its existing PBR mechanism. The Commission Panel directs FortisBC to complete its review of PBR prior to submitting its 2006 Revenue Requirements Application and to propose to the Commission its preferred process for review and implementation of its recommendations. The Commission will determine at that time an appropriate review process going forward.

[1] Subject to adjustments discussed elsewhere in this Decision.

2.5 2005 Demand Side Management Expenditure Plan

2.5.1 Application

FortisBC filed its planned 2005 DSM expenditures under Tab 10.1 of its Application. The planned expenditures are a one-year extension of FortisBC's 1999-2004 DSM Business Plan. As such, it is a one-year continuation of its existing resource acquisition strategy, programs and incentives. FortisBC proposes to file an updated DSM Potential Study by June 30, 2005 and to file a new DSM Business Plan, covering the period 2005-2014, by October 31, 2005. These latter proposals are a component of FortisBC's Resource Plan – Action Plan.

FortisBC's DSM plan is comprised of expenditures for programs in the Residential, General Service and Industrial sectors, as well as costs for Planning and Evaluation, including salaries, consulting fees for planning reviews, ongoing program monitoring, and periodic evaluation reports and training costs. Both the costs of the DSM Potential Study and the DSM Business Plan are included in the 2005 Planning and Evaluation costs. In sum, FortisBC has set out total 2005 DSM expenditures of approximately $1.8 million for forecast total 2005 savings of 19.1 GWh. At the time that FortisBC filed its Application, these amounts could be compared to 2004 forecast costs and savings of approximately $2.0 million and 21.0 GWh, respectively (for further detail, please refer to Exhibit B-1, Tab 10.1, pp. 5-11; Exhibit B-12, Response to BCUC IR 112.0-117.0; and Exhibit B-17, Report of the DSM Technical Committee).

FortisBC submits that its 2005 DSM Plan, filed in compliance with Section 45 (6.1)(c) of the UCA, is reasonable, prudent, and in the public interest, and therefore requests an Order of the Commission that the 2005 DSM plan meets the requirements of Section 45(6.2)(b) of the UCA and is in the public interest (FortisBC Argument, p. 57).

2.5.2 Demand Side Management Technical Committee

Commission Order No. G-14-05 specified that issues associated with DSM would be reviewed by a Technical Committee as an adjunct to the Hearing. The Committee comprised FortisBC and Commission staff as well as Registered Intervenors that expressed an interest to participate. The Commission directed the DSM Technical Committee to submit a report with recommendations to the Commission one-week prior to the commencement of the Hearing (Exhibit A-4).

FortisBC filed the Report of the DSM Technical Committee on March 9, 2005 (Exhibit B-17). The Committee considered a number of issues and concerns in detail over the course of two meetings. There was particular focus on the methodologies that FortisBC uses to forecast the costs and savings in its DSM Plan and to determine the cost-effectiveness of the component programs. FortisBC provided a detailed explanation, stepping through the calculation spreadsheets where appropriate, to the ultimate satisfaction of Committee members. The Committee agreed that a sensitivity analysis on input variables such as penetration rates would be a useful component of future filings and would improve the assessment of the cost-effectiveness of the various DSM programs. FortisBC intends to include sensitivity analyses in future DSM filings.

The Committee also highlighted a concern that the Terms of Reference for the DSM "2005 Energy Efficiency Potential Assessment", as included in Appendix D to Tab 10.1 of the Application, did not include any focus on capacity savings. In response, FortisBC updated the Terms of Reference for this study to eliminate the concern that capacity savings potential would not be addressed. The update to the Terms of Reference is included in Appendix One of the Report of the DSM Technical Committee (Exhibit B-17). FortisBC indicated that the cost of including a study of capacity savings would be re-allocated from other study components, leaving the total study costs of $24,000 unchanged.

The Committee recommended that the existing DSM Incentive Mechanism and DSM Incentive Committee continue for 2005. The Committee was of the view that there was no basis at present on which to rebase any DSM targets in advance of the comprehensive review of PBR that FortisBC intends to complete by the end of 2005 (refer also to FortisBC Argument, p. 51). The Committee recommended that there would be no need to call a DSM panel at the Hearing. After canvassing comment from those Registered Intervenors that did not participate in the DSM Technical Committee, the Commission accepted this recommendation (Exhibit A-16). No issues with respect to the DSM Plan were raised during the Hearing and no written submissions on the DSM plan were received in argument by any party.

2.5.3 Commission Panel Determinations

The Commission Panel has reviewed the FortisBC DSM Expenditure Plan and the Report of the DSM Technical Committee. **The Commission Panel approves the DSM Expenditure Plan as filed and acknowledges that this Plan meets the requirements of Section 45(6.1) of the UCA.**

The Commission Panel also accepts the recommendation of the DSM Technical Committee that the existing DSM Incentive Mechanism and DSM Incentive Committee continue for 2005. The Commission Panel is satisfied by the response of FortisBC to the other issues of concern raised by the Committee; namely, its intention to file appropriate sensitivity analyses in future filings and to include in its DSM potential study a focus on capacity savings potential. **The Commission Panel directs FortisBC to file its DSM potential study by June 30, 2005 and its 2005-2014 DSM Business Plan by October 31, 2005, the timelines proposed by FortisBC.**

2.6 Transition Plan

2.6.1 Introduction

Commission Order No. G-39-04 approved the acquisition by Fortis Pacific of a reviewable interest in Aquila(BC). The latter company became FortisBC after the acquisition.

Aquila(BC) and Aquila Networks Canada (Alberta) Ltd. ("Aquila Alberta") were affiliates of each other and operated on an integrated basis. The two organizations shared certain functions including, for example, executive management, customer call centre, most of the finance function, human resources, and legal services.

As part of Fortis Pacific's application to acquire a reviewable interest, the company represented that it would unwind certain of the shared functions between the B.C. and Alberta operations and establish and operate FortisBC on a stand-alone basis. Fortis Pacific submitted that establishing the utility on a stand-alone basis would allow it to effectively address customer service quality issues and operational improvements, focus the management's attention on the B.C. service area, and create a more transparent regulatory environment. The stand-alone entity would also have independent financing capacity in capital markets.

Commission Order No. G-39-04 directed Fortis Pacific and, as appropriate, FortisBC to file quarterly reports outlining planning activity, timetables and financial evaluation and impacts of their implementation. By the time the Oral Hearing commenced, the Company had filed two quarterly reports (Exhibit B-12, BCUC IR 123) and a detailed Transition Plan (Exhibit B-1, Tab 10.3). The quarterly reports and the Transition Plan illustrate FortisBC's intentions and progress to date on the changes being made in the areas of customer service and operations, and on setting up a stand-alone organization. FortisBC forecasts that the aforementioned activities will cause 2005 O&M expenses, before capitalized overheads, to increase by $1,158,000 (Exhibit B-66, p. 1). In 2005 FortisBC also expects to incur capital expenditures of $460,000 for the new call center in Trail, B.C. (Exhibit B-12, BCUC IR 124.1). The combined effect of these expenditures requires an increase of approximately $1.2 million in 2005 Revenue Requirements (Exhibit B-1, Tab 10.3, p. 13).

The following sections discuss the significant components of the FortisBC Transition Plan in greater detail.

2.6.2 Customer Service

Customer service is addressed separately in Section 2.7.

2.6.3 Establishment of a Stand-alone utility

During cross-examination, Mr. Hughes, President and CEO of FortisBC explained the advantages of operating a utility on a stand-alone rather than integrated basis. Mr. Hughes testified (T2: 82):

> "We believe that this stand-alone utility based in our B.C. service territory will not only produce improved customer service – why will it do that? Because it will have local knowledge, improved focus and greater responsiveness to trouble calls. But it will also, over time, produce lower costs. Let me give you a couple of examples: Lower employee turn-over, particularly in the call centre; lower building and rental costs; improved responsiveness to customer concerns and requests – for example, customer connection; and last and certainly not least, faster outage restorations."

Commission Counsel asked Mr. Hughes to provide hard evidence that demonstrates that lower costs come from a stand-alone utility (T2:114). Mr. Hughes replied:

> "Well, one of the first things I would point to, and between I think it was about 1992 and 2002 in Newfoundland Power with this model, essentially the O&M was flat. To run a utility over a period of that time with flat O&M obviously proves the value of the model. It's our experience from say Fortis (Ontario), Fortis – we changed that model and we saw a cost improvement. That was more integrated. We've seen it in many. If you go through those things I mentioned, what you will find if you look at the Fortis companies is that our cost performance improves, our customer satisfaction improves by adopting this model pre and post. In the last 15 years, Maritime Electric, you've seen the performance and cost performance." (T2:114-115).

To date, FortisBC has made significant progress toward creating the stand-alone entity. The Head Office has been established in Kelowna and the independent executive management team is mostly in place. FortisBC states that recruitment of staff includes a combination of internal reorganization, outside recruitment and transfers of skilled employees wishing to relocate. The Company also notes that no relocation and severance costs associated with the transfer of positions from Alberta are included in the 2005 Revenue Requirements (Exhibit B-1, Tab 10.3, p. 10).

FortisBC will have its own Board of Directors and it will include members from the service territory. The Board is expected to be in place by the end of 2005.

2.6.4 Field Services

FortisBC states that it intends to pursue two separate initiatives, both of which are aimed at improving customer responsiveness (Exhibit B-1, Tab 10.3, p. 12).

The first initiative is directed at reducing FortisBC's service restoration times. The Company is currently undertaking a comprehensive review with a view to establishing restoration targets applicable to all areas of its service territory. The review will be completed by the second quarter of 2005.

The second initiative is aimed at improving FortisBC's responsiveness to routine customer wait times for services such as new connections. FortisBC states that: "As in the case of restoration times, measurable targets will be established and regularly reviewed to ensure continued timely customer responsiveness on a consistent basis." (Exhibit B-1, Tab 10.3, p.12)

2.6.5 Submissions

BCOAPO opposes the $1.2 million increase in the 2005 Revenue Requirements that result from actions taken under FortisBC's Transition Plan. BCOAPO states that: "…it is not appropriate for it to require ratepayers to pay for the cost for restoring quality of service to levels that existed prior to the move to Calgary." (BCOAPO Argument, p.7) and "…that customers should not be required to bear the cost of improving customer service in the amount of $1.2 million…" (BCOAPO Argument, p. 25) It further argues that to the extent the $1.2 million is reflected in the O&M expenses, these expenses should be reduced accordingly (BCOAPO Argument, p. 25).

KOECA states: "…the Commission should not permit the company to subsequently be rewarded for restoring service levels which should never have been allowed to decline in the first place." (KOECA Argument, p. 2). KOECA argues that a way must be found to determine how much improvement the company must make before it can justify passing on service improvement costs to its customers. It further submits that: "The appropriate approach is to establish what service levels are now being targeted by the company and determine whether they were in fact already at that level in the past. If so, then the company should pay the entire cost of service restoration. If the company intends to provide service levels above those experienced in the past, then in fairness it should be able to recover costs for doing so, but only for the increment above past service levels." (KOECA Argument, p. 2).

IMEU submits is supportive of the efforts of FortisBC to focus on improving customer relations and customer service in the service territory, and to operate the utility in an efficient, safe and reliable manner. It is also pleased to see a locally managed stand-alone operation with a focus on customers and it states that: "…[the IMEU] particularly endorses the statement in FortisBC's argument that it believes that 'it [the stand-alone utility] will also produce the lowest possible costs for our customers over the long term'(Fortis Argument, Page 8)" (IMEU Argument, p. 2). Having made the above statements, IMEU continues to state several concerns, including its concern about the: "…increased costs being passed on to customers as a result of the transition of ownership from Aquila to FortisBC" (IMEU Argument, p.2).

2.6.6 Commission Panel Determinations

The Commission Panel has considered all the evidence and arguments related to this matter. The Commission Panel concurs that the largely one-time cost of moving many of the functions back to B.C. is appropriately an expense for the shareholder. However, it does not agree with Intervenors that the incremental ongoing or recurring costs associated with service improvement activities proposed in the Transition Plan should be borne by shareholders. In Section 2.3.3 the Commission Panel approved the forecast 2005 O&M expenses, before capitalized overheads (i.e. $39,569,000 subject to adjustments), which include the increase of $1,158,000 in O&M expenses related to the Transition Plan. **With respect to the establishment of the Trail Call Center, the Commission Panel also accepts the forecast 2005 capital expenditures of $460,000 and the associated increases in the 2005 Revenue Requirements.**

The targets applicable to service restoration times and customer wait times for services such as new connections should be filed with the Commission as per the Commission Panel's determinations set out in Section 2.4.2, paragraph (f).

FortisBC claims that a stand-alone utility will over time produce lower costs. The Commission Panel directs FortisBC to submit a report one year from this Decision that demonstrates the achievement of cost savings attributable to the stand-alone status of FortisBC. The Commission will determine the need for further reports on a prospective basis.

2.7 Customer Service

In its application to acquire a reviewable interest in Aquila(BC), Fortis Pacific provided evidence that "the conduct of FortisBC's business, including the level of service, either now or in the future, would be maintained or enhanced." (Exhibit B-1, Tab 10.3, p.3). FortisBC further states:

> "In addition to the intentions stated in the Application, multiple stakeholder and public consultations were conducted regarding the Acquisition and transition. During these consultations, the Company also stated its intention to, within a reasonable transition period: 1) improve the overall quality of service to customers; … " (Exhibit B-1, Tab10.3, p. 4)

The Commission, in considering the acquisition application, was mindful of the service level concerns as expressed by customers and the related undertakings of the Applicant. In Order No. G-39-04 approving the acquisition, the Commission made clear its expectations that:

> "… in due course and in a timely manner, steps will be taken to further consider and implement the plans and fulfill the commitments made in the presentations to stakeholders, in the Fortis Application and in the course of this public process." (Order No. G-39-04, Appendix A, p. 11)

With the amount of interest in and attention paid to customer service during the acquisition process, it is not surprising that customer service would be a topic of considerable focus for FortisBC and of much interest to Intervenors in this proceeding.

FortisBC addressed many customer service deficiencies under cross examination. The following is considered by the Commission Panel to be a representative sample of these deficiencies and FortisBC's view of them.

> "What's relevant is that the customer service level and the meter reading was just unacceptable. And we heard this very strongly from the customers." (T2: 103)

> "And another thing we found when we took over this utility and we made fairly good initial efforts to start changing it and we've still got a long way to go, is customer connections. The time from when a customer requested service in B.C. to when they were actually getting it, we felt was far too long." (T2: 116)

> "In principle, we are responding to customers -- what customers have been telling this utility for some time, and that is the level of dissatisfaction that they have with the customer service, the call centre, responsiveness, et cetera." (T2: 169)

> "Newfoundland Power in the early '90s was in a very similar situation as we see here in B.C. today. It was suffering from a very low customer service rating." (T3: 519)

In the course of the proceedings Intervenors were generally positive about to FortisBC's intentions and early progress with respect to improvements in customer service. IMEU's comments on the subject are, in the view of the Commission Panel, generally representative of Intervenor views:

> "The IMEU is supportive of the efforts of FortisBC to focus on improving customer relations and customer service in the service territory and has been generally impressed by the efforts of the new management of the Company to respond to customer concerns" (IMEU Argument, p. 2).

2.7.1 Metrics and Strategies

In Exhibit B-1 at Tab 10.2, FortisBC provides an informative overview of its views on customer service measurement and tracking. The Commission Panel is of the view that customer service may be measured as it occurs, in terms of objective measures of customer service activity, and after the fact, in terms of customer satisfaction response when surveyed. Typically, objective measures are an indication of performance in "real time", while survey responses measure reaction to performance after the fact and can lag actual performance by a considerable margin depending on the timing of the survey and the degree and nature of the interaction with the (in this case) service provider.

FortisBC indicated its intentions with respect to revising its approach to the measurement of customer service.

> "In general it seems more reasonable to directly measure things that are readily quantifiable, such as reliability, rather than measure them through qualitative questions in the survey. Going forward, it is intended that the customer survey tool be used to more accurately measure the quality and convenience of the customer's day-to-day interactions with the Company, and employ other metrics for strictly objective facets of customer service." (Exhibit B-1, Tab 10.2, p27)

FortisBC indicated that in addition to revising the survey questionnaire, it planned to establish metrics and key performance indicators for all departments for the purpose of linking departmental productivity levels in all areas to customer service. Some indicators that FortisBC believes are important to customers are (Exhibit B-1, Tab 10.2, pp 28-29):

- Billing Accuracy;
- Emergency response times;
- First call resolution;
- Commitment to follow-up;
- Tracking completion time for new service requests;
- Meter reading accuracy; and
- Field service complaints.

The following reflects the strategies that FortisBC is currently implementing, or intends to implement, believing that they will result in an improvement in customer service:

> "FortisBC plans to establish its own customer service functionality and is focused on strategies to improve service. These improvements include a more effective call centre, increased meter reading and billing accuracy, enhanced bill format and provision for in-person service. Also, improvements in field service delivery through more effective work processes and resource deployment will decrease wait times for services such as new connections and trouble call response. The Company intends to establish benchmarks to monitor its progress." (Exhibit B-1, Tab 10.3, p. 17)

FortisBC has identified that the costs of these initiatives, when netted against the forecast reduction in shared services cost from FortisAlberta, form the major part of the approximate $1.2 million increase in revenue requirements discussed in Section 2.6.1 (Exhibit B-1, Tab 10.3, p. 17).

2.7.2 Commission Panel Determinations

The increase in costs to support improvements in customer service has been approved elsewhere in this Decision. In defense of its O&M expense budget, FortisBC encouraged customers and the Commission to focus on the results of the utility's programs as reflected in objective measures of customer service levels (FortisBC Reply Argument, p. 19). The Commission Panel is concerned that although FortisBC indicates that it intends to establish benchmarks to monitor its progress in improving customer service, no specific objective measures have been identified by FortisBC as deliverables resulting from the increase in funding as requested and approved. In the view of the Commission Panel, it would be unreasonable under normal circumstances to approve an increase in funding in the absence of clear targets against which improved performance is expected and may be measured. However, in the circumstances, the Panel supports the need for substantial improvements in service and recognizes the need for urgency in undertaking the initiatives necessary to bring about these improvements.

Therefore, the Commission Panel directs FortisBC to file within 60 days of this Decision a comprehensive set of objective and measurable performance metrics showing respective performance at the beginning of 2005 (estimates where actual is not available) and targets for December 31, 2005 for service areas as follows:

1. **Billing Accuracy**
2. **Emergency response times**
3. **First call resolution**
4. **Commitment to follow-up**
5. **Tracking completion time for new service requests**
6. **Meter reading accuracy**
7. **Field service complaints**
8. **Call center**

Further, FortisBC is directed to report to the Commission by October 31, 2005, actual performance for each of the measures to September 30, 2005, and by January 31, 2006, actual performance for each measure to December 31, 2005.

2.8 Accounting Issues

2.8.1 Depreciation and Amortization Study

FortisBC's last formal depreciation study was undertaken in 1983 and a discussion paper on the service life of transmission and distribution assets was completed in 1999. The Negotiated Settlement Agreement for 2000-2002, approved by Commission Order No. G-134-99, included a reduction of depreciation rates (and therefore depreciation expense) for transmission and distribution assets from 35 years to 50 years, and a further offset to depreciation expense in the form of a Rate Stabilization provision. Neither change was based on an expert-prepared depreciation study examined by the Commission. Since 2000, depreciation rate changes have resulted in a lower annual depreciation expense of about $3.3 million. The Rate Stabilization Adjustment was utilized in 2001, which set-up a $3.1 million adjustment to offset accumulated depreciation (Exhibit B-12, BCUC IR 33.6-33.8; T5: 863-866; FortisBC Argument, pp. 36-38).

The DBRS credit rating report expressed that currently low depreciation rates are a challenge and it observed that the Company's current average depreciation rate appears low in comparison to other utilities (Exhibit B-12, BCUC IR 13.0, p. 2). Similarly, the Moody's credit rating report cites one of the Company's credit challenges to be the relatively low depreciation rate for rate-making purposes (Exhibit B-12, BCUC IR 15.0, p. 1).

Dr. Booth, expert witness for BCOAPO, stated that the depreciation rate should be based on the economic useful life of the assets and it shouldn't be fixed for other purposes (T4: 759). Mr. Meyers from FortisBC indicated that the Company expects to carry out a depreciation study later in 2005 and intends to perform depreciation studies on five-year intervals going forward (T5: 863). Mr. Wait argues that the depreciation rate for vehicles should be increased so that the difference between the vehicle sale value and depreciated value would be minimal (Wait Argument, pp. 3-4).

FortisBC proposes to conduct a depreciation and amortization study by an independent consultant during 2005, for submission with the 2006 Revenue Requirements application (Exhibit B-1, Tab 6, p. 9; Exhibit B-12, BCUC IR 33.6). The Company states that the depreciation study will address issues raised during the proceeding including disposition of the Rate Stabilization Account; different depreciation rates for the generation plants; and depreciation rates for fleet vehicles and computer software. FortisBC argues that it is inappropriate to make any changes to depreciation rates or methodology until a depreciation study is completed (FortisBC Argument, pp. 37-38).

FortisBC states that its policy is to record depreciation expense in the year after the assets are placed in service (Exhibit B-12, BCUC IR 29.1.2).

Commission Panel Determinations

The Commission Panel accepts that the currently approved depreciation rates should not be changed in 2005 until a formal depreciation and amortization study has been completed. The Commission Panel directs FortisBC to file a depreciation and amortization study as part of its next revenue requirements application. The next revenue requirements application will include a rate impact analysis for both with and without any depreciation and amortization rate changes.

2.8.2 Adjustment for Capital Expenditures

The Company calculates the Adjustment for Capital Expenditures on a quarterly weighted average instead of on a 13-month weighted average. The Company states that either method should provide similar results over the long term. The Company argues that should the Commission prefer that the Company move to a 13-month average for calculating the Adjustment for Capital Expenditures in the determination of rate base, the Company suggests that this change be introduced as part of the Company's 2006 Revenue Requirements application (FortisBC Argument, pp. 29-30; Exhibit B-12, BCUC IR 37.0; T5: 867-868).

Commission Panel Determinations

The Commission Panel agrees that the Company should continue to use the quarterly weighted average method to calculate the Adjustment for Capital Expenditures in 2005. The Commission Panel directs the Company to calculate the Adjustment for Capital Expenditures using the 13-month average method, commencing in 2006.

2.8.3 Allowance for Funds Used During Construction

AFUDC represents the cost of capital incurred by the Company while assets are under construction. The Company recognizes that customers should only contribute to assets that are "used and useful". Consequently, the Company deducts AFUDC from revenue requirements and adds it to capital costs, to be recovered through depreciation expense over the life of the asset (Exhibit B-1, Tab 8, p. 26).

The Company has calculated an AFUDC rate of 6.48 percent based on a return on equity of 9.78 percent and weighted average cost of debt of 6.66 percent (Exhibit B-1, Tab 8, p. 26; Exhibit B-12, BCUC IR 80.5 & 85.3).

The Company explained that AFUDC is calculated monthly on a project by project basis for projects with a forecast cost greater than $100,000 and expected to last more than three months duration. The Utility includes Construction Work in Progress ("CWIP") that attracts AFUDC in its rate base. Revenue requirements, including financing costs, are calculated on the mid-year rate base which includes CWIP. Revenue requirements are then reduced by AFUDC, to reflect the cost of financing the CWIP portion of rate base that is not used and useful. The Company stated that Terasen Gas and Pacific Northern Gas Ltd., both regulated by the Commission, do not include AFUDC as a reduction to revenue requirement and exclude CWIP subject to AFUDC from rate base. However the Company states that the net result of using either method should be the same (Exhibit B-12, BCUC IR 85.1-85.10).

The Company provided a reconciliation of the deduction of AFUDC in Schedule 3 to show that the Company has properly deducted AFUDC in calculating income tax expense (Exhibit B-79). Commission Counsel in cross-examination questioned the Company's use of including CWIP that attracts AFUDC in rate base and the practices of other utilities regulated by the Commission. Mr. Lee responded that the Company had no preference between the methodologies (T5: 873).

FortisBC argues that since 1990 it has included CWIP in the calculation of rate base, together with the corresponding deduction of AFUDC in the calculation of revenue requirements. FortisBC does not propose to change its current treatment, and believes that its current treatment better reflects the actual income tax and accounting treatment of AFUDC. If the Commission wishes to change the method of accounting for CWIP and AFUDC, FortisBC argues that the change should be applied prospectively beginning in 2006 as part of the Company's 2006 revenue requirement application (FortisBC Argument, p. 30).

<u>Commission Panel Determinations</u>

The Commission Panel accepts that the Company should continue to calculate CWIP and AFUDC using the current method in 2005. The Commission Panel directs FortisBC in its next revenue requirements application to review its current practice of including CWIP attracting AFUDC into rate base. The review should include a comparison of other electric and gas utilities regulated by the Commission, an analysis of the alternate methods, and a proposal by the Company on whether to continue or change its current AFUDC and CWIP methodology.

The Commission Panel directs the Company to recalculate its AFUDC rate based on the weighted average cost of debt from the Third Revised Application and the return on equity allowed through this Decision. The resulting approved AFUDC rate shall be applied to calculate the AFUDC amounts in 2005.

2.8.4 Capitalization of PowerSense Costs

FortisBC is proposing a change in the accounting treatment of certain PowerSense costs in the amount of $85,000, such that these costs are charged to capital rather than operations (Exhibit B-26, p. 4). The DSM Technical Committee discussed the reasons behind the request with only Mr. Wait expressing concern (Exhibit B-17, p. 3).

Mr. Wait argues that the $85,000 charge for DSM awareness should continue as an operating expense and not be capitalized. He expressed concern for capitalizing costs that do not have physical assets attached and the procedure would cost ratepayers more for ROE and equity (Wait Argument, p. 9). Currently the Company amortizes DSM (deferred energy management) costs over 8 years (Exhibit B-12, BCUC IR 34.1-34.3).

Commission Panel Determinations

The Commission Panel approves the change in accounting treatment of certain PowerSense costs as proposed by the Company. The Commission Panel directs that the upcoming depreciation and amortization study will address the appropriateness of the current amortization period for deferred DSM costs.

2.8.5 Deferred Charges

Net-of-tax Deferral Accounting

Currently, FortisBC treats DSM costs net-of-tax as directed in Commission Order No. G-55-95. All other deferred charges that have been recorded by the Company are on a gross of tax basis. At Transcript Volume 5, page 887, Commission Counsel questioned the appropriateness of recording all deferred charges on a net-of-tax basis. Mr. Meyers responded that, in his opinion, the net-of-tax treatment is appropriate to ensure proper matching of costs and benefits (FortisBC Argument, p. 59).

The Company proposes that deferred amounts related to the proposed 2005 O&M Expense and power purchase sharing mechanisms be recorded net-of-tax so that the associated income tax is correctly matched either to the customers or the shareholder (Exhibit B-12, Response to BCUC IR 34.5). The Company does not propose to extend net-of-tax treatment to other deferral accounts. The Company is of the position that any change in the treatment of deferred charges must apply on a prospective basis only, and should be made only after a full assessment of the impact has been completed (FortisBC Argument, pp. 59-60).

The Commission believes that a consistent treatment of deferral accounts is warranted to ensure proper matching of costs and benefits. **The Commission Panel directs that all deferred charges (excluding preliminary and investigative costs charges transferred to capital projects) be treated using net-of-tax deferral accounting commencing in 2005.**

Tax Rate for Net-of-tax Deferral Accounting

The Company currently books net-of-tax deferrals using the combined federal and provincial statutory tax rate including federal surtax. The 2005 combined statutory tax rate with surtax is 35.62 percent and 34.5 percent without surtax. Mr. Lorimer agreed that the federal surtax was deductible against the large corporation tax. In response to a question by Commission Counsel, Mr. Lorimer rationalized that the 35.62 percent tax rate was appropriate (Exhibit B-12, BCUC IR 34.1; T5 887-888).

In its calculation of the large corporation tax for 2005 the Company has included a federal surtax reduction to compute the net payable large corporation tax (Exhibit B-12, BCUC IR 81.5).

In 2005 the ability to apply the federal surtax to reduce large corporation tax effectively excludes the federal surtax in the combined corporate income tax rate. **The Commission Panel directs that the tax rate to use for net-of-tax deferral accounting is the net effective tax rate to the Company. For 2005 the appropriate tax rate to use for net-of-tax deferral accounting is 34.5 percent without the federal surtax.**

Cost of Regulatory and Related Activities

The Company requests approval for the deferral of the cost of regulatory and related activities. In Table 6.4B, Forecast 2005 Deferred Charges and Credits, the Company proposes to include in 2005 forecast deferral additions of $250,000 for the 2005 Revenue Requirements proceeding, $75,000 for the 2006 Revenue Requirements proceeding, and $150,000 for Other Regulatory proceedings (Exhibit B-1, Tab 6, p. 13).

The Company explained the Other Regulatory proceedings amount is a provision for expected and unexpected regulatory proceedings during the year. The Company anticipates the most significant costs would be for the 2005 Generic Return on Equity hearing plus intervention in proceedings of other utilities such as BC Hydro’s Rate Design hearing. The Company states that it is not possible to estimate costs with a reasonable degree of certainty until the scope and process of a proceeding has been determined (Exhibit B-12, BCUC IR 34.7).

The Commission Panel approves gross deferral account additions of $250,000 and $75,000 in 2005 for the 2005 and 2006 Revenue Requirements proceedings, respectively. The Company will file with the Commission upon completion of each of these two proceedings a review of the actual costs, a comparison of the costs from actual to budget, and a demonstration that the costs have been prudently incurred.

The Commission Panel denies the $150,000 provision for Other Regulatory proceedings to be included in rate base. The Commission Panel directs the Company to set-up a non-rate base short-term interest bearing deferral account for each regulatory proceeding that it proposes to seek cost recovery for. The account will collect actual costs incurred for each proceeding. At the conclusion of each proceeding the Company may apply for a prudency review of actual incurred costs for inclusion in rate base as a deferral account.

Series 04-1 Senior Unsecured Debentures Issue Cost and Amortization

FortisBC requests approval for the issue cost of the Series 04-1 Senior Unsecured Debentures in the amount of $2,091,000. The Company also requests amortization of the issue cost of the Series 04-1 Senior Unsecured Debentures in the amount of $2,091,000 over ten years commencing on January 1, 2005. The amortization period matches the 10-year term of the bond (Exhibit B-26, p. 3; Exhibit B-1, Tab 8, p. 18; Exhibit B-12, BCUC IR 23.1).

The Commission Panel approves the $2,091,000 issue cost of the Series 04-1 Senior Unsecured Debentures and the amortization over ten years commencing on January 1, 2005.

Amortization of the Costs Incurred for 2004 Revenue Requirement process

The Company requests amortization of the costs incurred in FortisBC's 2004 Revenue Requirements NSP over a one-year period (Exhibit B-26, p. 3; Exhibit B-12, BCUC IR 34.3).

The Commission Panel approves the amortization of costs incurred in FortisBC's 2004 Revenue Requirements NSP for a one-year period in 2005.

Costs and Amortization of the System Development Plan and Resource Plan

The Company requests the amortization of the costs of the 2005-2024 System Development Plan and the 2005 Resource Plan, in an aggregate amount of $900,000, over five years commencing on January 1, 2005 (Exhibit B-26, p. 3). The December 31, 2004 balances are $800,000 for the System Development Plan and $100,000 for the

Resource Plan (Exhibit B-12, BCUC IR 29.0, Table 1-B (2005)). The Company states that these planning activities are carried out at intervals of approximately five years, and are considered to be an ongoing, although intermittent, operating expense. Therefore, the Company proposes to include the amortization of costs in O&M expense (FortisBC Argument, p. 60).

The Commission Panel approves a five-year amortization for each of the System Development Plan and the Resource Plan costs. The Commission Panel determines that net-of-tax deferral accounting is to be used for deferred charges. Consequently, the System Development Plan and Resource Plan costs are not to be amortized to operating expense. Instead these costs are to be amortized to deferred amortization expense.

Capital Cost Allowance Rate Change Deferral

In its Revised Application, FortisBC incorporates changes to the 2005 Revenue Requirements to reflect capital cost allowance ("CCA") rate changes relating to new transmission and distribution assets announced in the February 23, 2005 Federal Budget (Exhibit B-19, p. 6). FortisBC requests approval of a deferral account and recovery in 2006 of higher income tax expense that will arise in 2005 if the new CCA rates announced in the February 23, 2005 Federal Budget are not enacted prior to December 31, 2005 (Exhibit B-26, p. 5).

The Commission Panel approves a deferral account and recovery in 2006 of higher income tax expense that arises in 2005 if the new CCA rates announced in the February 23, 2005 Federal Budget are not enacted prior to December 31, 2005.

2.8.6 Provision for Income Tax Audits

The Company has included an amount of $100,000 in its 2005 Revenue Requirements as a provision for income tax audits. The Company has been audited by the Canada Revenue Agency ("CRA") for the years up to and including 1998. The Company expects that it will be audited for the years subsequent to 1998 in the near future. The Company believes it is both reasonable and prudent to include this provision in its 2005 income tax expense. The Company indicated that a cumulative provision for income tax audits for the years 1999 to 2004 exists, in the amount of $350,000. FortisBC proposes this provision be retained pending an audit from CRA for these years. Any unused provision upon completion of the audits would be credited to the benefit of customers in calculating the following year's revenue requirement (FortisBC Argument, p. 33; Exhibit B-77, Undertaking U-44).

FortisBC confirmed that the accumulated provisions for tax audits have not been factored into the rate base calculations (Exhibit B-78, Undertaking U-45). IMEU argues that it does not believe that the provision for tax audit should be maintained. Also, IMEU submits that the $350,000 which has been collected from customers should be returned to customers in 2005 (IMEU Argument, 17).

FortisBC in its reply to IMEU believes that the Company's position is a prudent method of providing for the eventual costs of tax audits, and that its proposal to retain the provision and to dispose of any unused amounts upon completion of the audits be approved by the Commission (FortisBC Reply Argument, pp. 29-30).

Commission Panel Determinations

The Commission Panel directs the $100,000 provision for tax audit to be removed from the 2005 Revenue Requirements. The Commission Panel also directs that the cumulative provision of $350,000 for income tax audits already collected be returned to ratepayers in the 2005 test year.

2.8.7 Capital Tax Refund

FortisBC was reassessed for B.C. Capital taxes for the taxation years 1994 through 1998. The primary issues arising from the assessments arose from the netting of CIAC against book value and the netting of certain deferred charge credits against deferred charge debits for purposes of computing the Company's paid-up capital for capital tax purposes. The Company paid the reassessed amounts and appealed the reassessments. In early 2004, the Company, together with Terasen Gas, met with representatives from the B.C. Ministry of Finance to put forth its position on the calculation of the capital taxes. On February 11, 2005 the Company received notice that its appeal has been allowed by the Minister of Finance, and it is awaiting final reassessment (Exhibit B-12, BCUC IR 82.1).

The Company proposes that the capital taxes refund amount, including interest and net of related income taxes, be shared equally between the Company and its customers. The Revised Application includes a provision for one-half of the estimated B.C. Capital Tax refund of $908,000 applied on an after-tax basis, to reduce the 2005 B.C. Capital Tax expense by $292,000 (Exhibit B-19, p. 7). FortisBC argues that since the Company aggressively pursued the appeal, and in view of the fact that PBR is intended to provide incentives to the Company to find ways to reduce cost and to share these cost savings with the customer, it considers it reasonable that the refund be shared on a 50-50 basis (FortisBC Argument, p. 35).

Mr. Meyers agreed that capital tax was a flow-through cost borne by the ratepayers and that the ratepayers paid for the costs of pursuing the appeal. Mr. Meyers stated that the Company aggressively pursued the assessment and that the sharing of the benefit would continue to provide incentives to the Company to continue to appeal similar types of assessments. Upon further questioning from Commission Counsel, Mr. Meyers agreed that as a part of the Company's normal business operation it has an obligation to pursue the tax assessment to keep costs down. Commission Counsel also questioned why the Company was treating the refund on an after-tax basis for the flow-through to customers. Mr. Lorimer replied that the B.C. Capital Taxes, as opposed to the large corporation tax, was a tax deductible item in those years (T5: 843-846).

IMEU does not support the regulatory treatment of B.C. Capital Tax as proposed by the Company. IMEU submits it is completely inappropriate for the Company to be claiming any portion of any refund or positive assessment from the appeals of these tax matters. IMEU considers that, since the customers bore the full cost of the appeals and bore the full cost of the taxes paid during the period, the customers should be entitled to a full refund of the success of the appeals. IMEU notes that if the challenge were unsuccessful, yet prudently undertaken, the cost of the pursuit of the appeal would have been borne by the customers (IMEU Argument, pp. 3, 15-16).

BCOAPO does not support a sharing of the B.C. Capital Tax refund. BCOAPO notes that Mr. Lorimer admitted that FortisBC was not the only utility to appeal the capital tax assessment (T3: 516). BCOAPO argues there is no evidence that the efforts of FortisBC, rather than the efforts of other utilities, were responsible for the capital tax refund (BCOAPO Argument, pp. 25-26).

Commission Panel Determinations

The Commission Panel denies the proposed sharing of the B.C. Capital Tax refund. The Commission Panel directs the Company to include in 2005 the full after-tax refund amount without any sharing to the Company.

3.0 2005 CAPITAL PLAN AND 2005-2024 SYSTEM DEVELOPMENT PLAN

3.1 Introduction

In conjunction with its 2005 Revenue Requirements filing, FortisBC filed its 2005-2024 System Development Plan and its 2005 Capital Plan. FortisBC states that these plans are intended to comply with the requirements of Section 45 of the UCA (Exhibit B-1, Tab 1). Section 45(6) of the UCA states that “A Public Utility must file with the Commission at least once each year a statement in a form prescribed by the Commission of the extensions to its facilities that it plans to construct.” Section 45(6.1) requires that the utility file a capital expenditures plan for a period specified by the Commission in addition to plans for the acquisition of energy and plans for reducing the demands for energy.

In its November Application FortisBC stated that it was seeking an Order that its 2005 System Development Plan meets the requirements of Section 46(6) of the UCA and an Order that its 2005 Capital Expenditure Plan satisfies the requirements of Section 45(6.2)(a) and (b) of the UCA (Exhibit B-1, Tab 9, pp. 5-6). In its Second Revised Application FortisBC no longer sought an Order for the System Development Plan. In clarification, Mr. Macintosh stated that the Orders FortisBC is seeking are contained in the Second Revised Application and did not include an Order for the approval of the System Development Plan, but required an order approving the 2005 Capital Plan (T2: 67). Mr. Debienne stated that although they were not seeking approval, the System Development Plan needs to be considered when evaluating the Capital Plan (T3: 345).

3.2 2005-2024 System Development Plan

The System Development Plan is a long range planning document for capital expenditures on the transmission and distribution system. It considers a 20-year time frame for the transmission system and a 5-year time frame for the distribution system and was preceded by the 1998 Master Plan. Although the time frame for the report is 20 years, the majority of expenditures are anticipated to occur in the next five years. The total transmission and distribution capital forecast for the first five-year period is in excess of $400 million (Exhibit B-1, Tab 9, p. 19).

Inputs to the plan include the forecast growth for the Kootenay and Okanagan regions and assessments of equipment condition and maintenance plans. Each resulting project was assessed against criteria for safety, public impact, restoration time, thermal capacity, system effect of failure, and voltage. Some projects were given a mandatory designation for safety reasons (Exhibit B-2, pp. 2-4).

3.2.1 Bulk Transmission Plan

The following section discuses system deficiencies and/or changes from the 1998 System Plan. Although the most significant deficiencies were addressed by the 230 Kootenay Development project and the South Okanagan Supply reinforcement project, FortisBC has identified several other areas of concern.

One area of concern is the reliability of supply to the City of Kelowna. FortisBC identified that Kelowna will be exposed to a significant load loss from the coincident loss of circuits 72 and 74 or BC Hydro's 2L255 and 2L256 from Vernon. (Exhibit B-2, p. 10). With this occurrence Kelowna could experience a loss of two thirds of its load, with the remainder of load under rotating blackouts. FortisBC testified that the concern with these lines lies with the fact that they share common rights of way and could be subject to outage events such as forest fires or other common mode outages. It was also concerned about the exposure to Kelowna under conditions of maintenance outages. This condition is referred to as an N-1-1 condition. In the previous plan only a loss of one line was considered. However, according to Western Electricity Coordinating Council ("WECC") standards, when it is reasonable to assume a multiple element outage due to one cause a utility must consider the multiple element outage under N-1 contingency standards (T2: 265-267). The solution to this concern is to replace the 161 kV line with a 230 kV transmission line from Vaseux Lake Terminal to the Anderson Terminal in Penticton.

Other changes identified include the supply to the Boundary area and to Osoyoos as well as the need for additional Remedial Action Schemes for Vaseux Lake Terminal and Kelowna to prevent voltage instability in the Penticton/ Oliver and the Kelowna areas (Exhibit B-1, Tab 9, p. 18; Exhibit B-2, pp. 12, 13, 17, 29, 40).

3.2.2 Transmission and Distribution

FortisBC identified a significant number of sub-transmission and distribution projects required for growth and sustaining projects. These are listed in Appendix C of Exhibit B-2 on pages 2 and 3. Distribution projects are listed on page 4 and Telecommunications, Scada, and Protection projects are listed on page 5. All projects have been prioritized according to the criteria described above, and are listed on pages 6 and 7 of Appendix C.

3.2.3 Rate Impacts

FortisBC estimated that the Capital Plan would result in an average increase in rates of 4.8 percent per year for the first five years (Exhibit B-12, BCUC 92.3). As a result of further questions during the Technical Committee meetings FortisBC also estimated that the impact of all other cost components with the Capital Plan included is an average rate increase of 5.2 percent per year (Exhibit B-20, Appendix 1).

However Mr. Debienne stated that the results calculated in response to BCUC 92.3 were misleading because the table contained the Capital Expenditures for the System Development Plan in 2005 and then included the Capital expenditures for the entire company in the remaining years to 2010 (T2: 228). Mr. Debienne also stated that a more accurate representation of the impacts of the System Development Plan can be found in Appendix 1 to Exhibit B-20. While this Exhibit shows the rate impacts for all capital expenditures, the rate impact for the System Development Plan would be approximately two-thirds of that, or a cumulative impact of 20 to 25 percent over six years (T2: 231-232).

3.2.4 Submissions

Arguments from IMEU, BCOAPO, and NRI were generally supportive of the System Development plan and the possible improvements in reliability, but all expressed some concern for the rate impact. IMEU expressed some concerns about the completeness of the System Development Plan, but was encouraged by the Company's commitment to have an open dialogue on the Plan. Mr. Wait had specific comments on the Big White Project and the East Osoyoos Substation, the Boundary reconfiguration, and the lines 30, 32, and 37 (Kaslo, Crawford Bay, Lambert Terminal areas). He also suggested that the 230 kV line from Vaseux Lake to Penticton was not needed and should be delayed. In conclusion he wished to have the System Development Plan address the issues he raised.

FortisBC argued that the System Development Plan and the Capital Plan were developed to ensure that investments in the existing system are sufficient to maintain system integrity and reliability and to optimize the life of the company's assets (FortisBC Argument, p. 9). FortisBC believes the plans are efficient and that it has economized it to the extent possible. However it notes that it is continuing to do analysis to optimize the plan on a year to year basis. (FortisBC Argument, p. 12-13). Regarding the impact on rates, FortisBC acknowledges the impact and notes that for the next 6 to 7 years customers will see a rate bulge as the system is renewed, but in the long term customers will enjoy relatively low rates because of the low cost of generation. In comparison to other utilities, the cost of equipment will be the same, as the company uses the same material and practices as other utilities and that therefore the rates will be comparable to other utilities on that basis (FortisBC Argument, pp. 12-15).

With regard to the need for N-1-1 criteria for the City of Kelowna, FortisBC acknowledges that this is a change from previous criteria but believes it to be necessary because of the possible impacts on Kelowna (FortisBC Argument pp. 14-15).

3.2.5 Commission Panel Determinations

Although the Commission has not been requested to approve the System Development Plan, the Commission Panel has several comments. First, the Commission Panel commends the effort FortisBC has put forward in constructing the System Development Plan. The Commission Panel believes that FortisBC's thorough review of the needs of the system and prioritization of the identified projects will greatly assist future capital expenditures investment decisions. Second, the Commission Panel encourages FortisBC to treat this plan as a living document, to continue to consult with stakeholders, and to keep the inputs to the plan current as the plan evolves. With respect to the rate impacts of the System Development Plan, the Commission Panel is concerned that sustaining a rate increase of approximately 5 percent per year over the next six years may be difficult. Thus, the Commission Panel suggests that for the next capital plan review, and subsequently thereafter, FortisBC should develop alternate scenarios that envision a perhaps less efficient plan but which would involve delaying capital expenditures. The Commission Panel is not suggesting that these scenarios would be preferred, but that their cost impacts need to be known in order to make choices between lower rate increases and higher long term costs. The Commission Panel also notes that customers have enjoyed relatively lower rates than other utilities for a considerable period during the 1980's and 1990's when capital investment levels were much lower.

With respect to the appropriate reliability levels for the City of Kelowna, the Commission Panel notes that the criteria of N-1 is a minimum standard set by the WECC for bulk transmission systems and adopted by most utilities. The Commission Panel acknowledges that there are situations (particularly in large urban centers) where the consequence of a lower probability occurrence of an N-1-1 or N-2 event requires the N-1 standards to be exceeded. Each case is a judgment call and must be evaluated on its own merits. However it is common practice to have N-2 contingency levels for certain load centers in large urban centers (e.g. Vancouver and Victoria). **The Commission Panel accepts that an N-1-1 contingency level for Kelowna is appropriate at this time.**

3.3 2005 Capital Plan

3.3.1 2005 Capital Plan Summary

FortisBC is seeking an order that the 2005 Capital Plan, as setout in Tab 9 of Exhibit B-1, satisfies the requirements of Section 45 (6.2) (a) and (b) of the UCA. The 2005 Capital Plan contains expenditures of $49.4 million (AFUDC and loadings included) for which project approval has been previously received from the Commission. These projects are the Kootenay 230 kV System Development Project, the South Okanagan Supply Reinforcement Project, the Kelowna Area Upgrade and the Upgrade and Life Extension projects involving Unit 5 and Unit 6 at the Upper Bonnington power plant. (Exhibit B-1, Tab 9, p. 4).

As part of the Capital Plan FortisBC proposed that the following four criteria be used to determine if a project should be subject to a CPCN application:

1. the total project cost is $20 million or greater; or
2. the project is likely to generate significant public concerns; or
3. FortisBC believes for any reason that a CPCN application should proceed; or
4. after presentation of a Capital Plan to FortisBC stakeholders, a credible majority of those stakeholders express a desire for a CPCN application.

FortisBC argued that these criteria were consistent with Commission Order No. G-96-04 and directives regarding the British Columbia Transmission Corporation ("BCTC") (Exhibit B-1, Tab 9, p. 6).

FortisBC notes that the Big White Supply Project will be the subject of a Certificate of Public Convenience and Necessity ("CPCN") Application in 2005.

The 2005 Capital plan for Transmission, Stations, Distribution and Telecommunications is based primarily on the System Development Plan, while the 2005 Capital Plan for Generation is based on the Upgrade and Life Extension program as well as other capital sustaining requirements (Exhibit B-1, Tab 9, p. 5).

3.3.2 New Projects

Generation

By a December 8, 2004 letter, FortisBC advised the Commission that in keeping with its proposed CPCN criteria it did not intend to file a CPCN for the Lower Bonnington Upgrade and Life Extension Project. However on May 19, 2005 FortisBC submitted a CPCN application for this project. This project was originally delayed pending the outcome of an agreement with BC Hydro to clarify the entitlement benefits for an upgraded turbine. The subsequent agreement improved the actual benefits of the upgrade.

Transmission and Stations

Although there are numerous small sustaining capital projects, the main projects driving new capital are the Big White Supply project at a total cost of $24.5 million with $3.0 million in 2005; the Ellison Distribution source at a total cost of $8.25 million with $0.25 million in 2005; the Black Mountain distribution source at a total cost of $7.25 million and $0.25 million in 2005; and the new East Osoyoos source at $5.75 million with $0.25 million in 2005; and the Kettle Valley distribution source at a total cost of $7.65 million with $0.15 million in 2005.

Distribution Projects

The Commission Panel notes that the largest expenditure is for new connects ($4.5 million) with the remainder made up of a larger project with respect to the Creston upgrade to the Lambert Terminal project as well as a large number of smaller projects.

Telecom, SCADA, and Protection and Control Projects

The largest project in this category is the Distribution Substation Automation project with total expenditures forecast at $6.2 million dollars with $0.60 million in 2005. The remainder consists of a number of modest sustaining projects totaling $1.4 million.

CPCN Requirements

As discussed above, FortisBC has proposed that a number of criteria be used to guide FortisBC when applying for CPCN's. No intervenors commented on the CPCN criteria.

3.3.3 Commission Panel Determinations

The Commission Panel confirms that the 2005 Capital Plan satisfies the requirements of Section 45(6.2)(a) and (b) of the UCA.

With regard to the CPCN Criteria, the Commission Panel is in general agreement with FortisBC's assessment of the appropriate criteria to guide the Company and the Commission when applying for CPCN's. However FortisBC has missed an important distinction with respect to the BCTC application. BCTC has acknowledged that the Commission has the authority to designate any projects it deems necessary for a CPCN application, regardless of the criteria. **In exercising this prerogative the Commission will be guided by the suggested criteria. However, in practice the Commission intends to review each year's capital filings and will determine with reasons which projects will require CPCNs.**

The Commission approves all capital projects listed in Tab 9 of Exhibit B-1, except for the following projects, for which the Commission Panel directs FortisBC to submit CPCN applications.

1. **Big White Supply:** As FortisBC suggests, this project is required because its total cost will exceed $20 million and because of public concerns with respect to routing and capital cost recovery.

2. **East Osoyoos Source:** This is required because of uncertainty with respect to the timing of this project and alternative solution. In addition, there seems to be some uncertainty regarding the supply from Bentley substation.
3. **Kettle Valley Distribution Source:** As with (2) above, there appears to be some uncertainty with regard to the best solution for the Boundary area. The Commission Panel is of the view that allowing public comment on the proposed solution would be of value.
4. **Distribution Substation Automation:** This is required because it is not clear to the Commission Panel what the possible risks and benefits are associated with the project, what precedent it may set for future projects, and if FortisBC is selecting the appropriate technology.

The Commission Panel invites FortisBC to withdraw its May 19, 2005 CPCN application for the Lower Bonnington Upgrade and Life Extension Project.

4.0 2005 RESOURCE PLAN

4.1 Background

The Commission's mandate to direct and evaluate the resource plans of energy utilities is intended to facilitate the cost-effective delivery of secure and reliable energy services. The Commission's Resource Planning Guidelines (the "Guidelines") outline a comprehensive process to assist utilities in the development of such plans. The Commission requires that any resource plans filed under Section 45(6.1) of the UCA be prepared in accordance with its Guidelines.

The Commission requires consideration of all known resources for meeting the demand for a utility's product, including those which focus on traditional and alternative supply sources, and those which focus on conservation of energy and DSM. Resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run. The process aids in defining and assessing market-based costs and benefits, while also entailing the assessment of tradeoffs between other expected impacts that may vary across alternative resource portfolios. Such impacts may be associated with objectives such as reliability, security of supply, rate stability and risk mitigation, or specific social or environmental impacts. In sum, a resource planning process that assesses multiple objectives and the tradeoffs between alternative resource portfolios is key to the development of a cost-effective resource plan for meeting demand for a utility's service (Guidelines, pp. 1-2).

On December 21, 2004 FortisBC filed its Resource Plan as Volume 3 of its 2005 Revenue Requirements Application. FortisBC prepared and filed its Resource Plan in response to the Commission's directive to utilities to file such plans as contemplated by Section 45(6.1) of the UCA. FortisBC states that its Resource Plan is consistent with the Guidelines.

4.2 2005 Resource Plan Summary

FortisBC's 2005 Resource Plan is a study of its load and resource Requirements over the period 2005-2024. It summarizes its Resource Plan objectives as to reliably meet customer load requirements, in agreement with stakeholder expectations, with existing and new resources if needed, with minimum rate and environmental impacts and with the guidance of the B.C. Energy Plan.

FortisBC's long-term firm requirements and its current planning in this regard establish the initial frame of reference for its Resource Plan. FortisBC's hydroelectric generation plants are expected to supply approximately 214MW of firm capacity and 1,569GWh of energy in 2005, or roughly 30 percent and 50 percent of its capacity and energy requirements, respectively. FortisBC has long-term purchase agreements for additional firm resources with the Columbia Power Corporation/CBT Power Corporation ("CPC/CBT"), for 149MW of capacity and 984GWh of energy through 2056, and with BC Hydro under the PPA, for 200MW of capacity and associated energy through 2013. The total of its long-term firm resources currently supply about 98 percent of its energy needs and about 76 percent of its capacity requirements (Exhibit B-4, pp. 5, 19). FortisBC assessed its load and resource balance through 2024 with its existing and planned resources. Its planned resource additions include its Upgrade and Life-Extension program, Upper Bonnington Re-Powering, and purchase options from local existing and planned resources such as Cominco and the CPC/CBT Brilliant Expansion. The results of its study indicate that with existing owned resources and supply contracts, FortisBC will be able to meet almost all of its energy requirements until 2013 when the 200MW BC Hydro PPA potentially expires. FortisBC notes that there will continue to be a small capacity-related energy shortfall during peak winter periods, growing only slightly to 2013 given that the energy take under the BC Hydro PPA can increase as load grows.

FortisBC's current strategy for acquiring additional resources includes the purchase of capacity-related energy from the market with a combination of short-term advance purchases of capacity and/or energy blocks as well as purchases from the spot market. FortisBC states that it favours capacity purchases because they allow peaking energy to be supplied from BC Hydro under the PPA and because they do not involve any surpluses. FortisBC has regarded this as a more cost-effective strategy than securing long-term firm resources to meet peak demands because it minimizes over-purchases of energy, with the consequent risk that the sell-back of un-needed energy will be at a lower price. Further, FortisBC is constrained from exporting when taking energy from BC Hydro under the PPA. FortisBC acknowledges that while it views its current strategy as cost-effective, it faces the risk of fluctuating power purchase expenses given the exposure to market volatility, as well as reliability risk associated with the market's ability to supply its peaking needs (Exhibit B-4, pp. 19-20). FortisBC's resource planning allowed it to review this strategy in view of expected load growth over the planning horizon. It also allowed FortisBC to investigate the impact if the BC Hydro PPA is not be renewed after 2013, given the significant annual shortfalls in capacity and energy that would occur under this scenario.

FortisBC's Resource Plan presents a comprehensive set of Case Scenarios to assess various strategies to maintain its Load and Resource balance over the 2005-2024 planning horizon. FortisBC models one set of three cases under which it pursues its existing market strategy, while considering separate scenarios wherein the BC Hydro PPA continues until 2024 with no new firm resources added (Case A-1), the BC Hydro PPA ends in 2013 and no new firm resources are added (Case A-2), and the BC Hydro PPA ends in 2013 and is replaced with a new firm resource (Case A-3). FortisBC models a second set of three cases under which it pursues a new market strategy and assumes the BC Hydro PPA continues, while considering separate scenarios wherein no new firm resources are added (Case B-1), a 75MW Peaking Plant is added in 2008 (Case B-2), and a BC Clean Resource (Biomass Plant) is added in 2010 (Case B-3). And finally, FortisBC models a third set of three cases under which it pursues a new market strategy and assumes the PPA ends in 2013, while considering separate scenarios wherein the BC Hydro PPA is replaced with a new 250MW firm resource (Case C-1), a 75MW Peaking Plant is added in 2008 and the BC Hydro PPA is replaced with a new 250MW firm resource (Case C-2), and a BC Clean Resource (Biomass Plant) is added in 2010 and the BC Hydro PPA is replaced with a new 250MW firm resource (Case C-3).

There are a number of assumptions common to the analysis of each Case, including common discount rates (nominal 8, 10, and 12 percent values), common Load and DSM forecasts and, where relevant, common forecast market prices for electricity based on a forecast of Mid-C index values for the 2005-2024 period. FortisBC's Resource Plan considers Load and DSM forecasts consistent with the forecasts provided in support of its 2005 Revenue Requirements Application. While it assumes a constant DSM forecast over the time period of its Resource Plan, FortisBC addresses uncertainty in the factors underlying its load forecast, such as economic and population growth rates, by incorporating a High and Low load forecast. The High forecast assumes a 25 percent increase in the annual load growth rate, while the Low forecast incorporates a 20 percent reduction in the annual load growth rate (Exhibit B-4, pp. 22-30, 59).

In contrast to the existing market strategy modeled in the A-Cases, under which the shortfall between firm resources and requirements is met with short-term monthly or one-year ahead purchases (aside from roughly 75MW of purchases in the spot market), the new market strategy pursued under the B Cases is characterized by meeting the shortfall with medium-term three to five year energy block purchases (again, with roughly 75 MW of spot market purchases). FortisBC modeled the new market strategy as a test of the protection it affords against market volatility risk and reliability risk under the expectation, in part, that this strategy is less susceptible to price shock risk. Medium-term block purchases are considered an effective hedge against price shock because if prices rise the sell-back price of surpluses rises accordingly, offsetting increased costs.

In sum, the modeling of each Case allows FortisBC to assess the incremental cost and rate impacts associated with moving to a new market strategy, losing the BC Hydro PPA, building a peaking plant resource, or building a BC Clean energy resource. FortisBC assessed the sensitivity of its modeling results to changes in discount rates, variations in market prices and the degree of exposure to market price volatility, as well as changes to the assumptions regarding the relative amounts of energy purchased in the spot market in the relevant Cases.

FortisBC concludes, in part, that:

- The existing market strategy under the expected load forecast is the lowest-cost portfolio under the scenario that the BC Hydro PPA continues until 2024 (Case A-1);
- The existing market strategy would continue to be the lowest-cost portfolio if it is not possible to renew the PPA (Case A-2), but the exposure to the market under this scenario would likely be unacceptable, notwithstanding the uncertainty about the viability of the market at that time, and would require the addition of a new long-term firm resource;
- If the PPA is replaced by a new long-term firm resource, the impact on power purchase costs are expected to be significant, an estimated five percent levelized rate impact;
- The new market strategy, while more costly, could be justified with an extreme rise in market prices of approximately six times, but only marginally justified with a moderate rise of about three times, considering also the possibility of price decreases and the benefits of improved reliability;
- A more detailed study of the new market strategy would be required in order to more fully assess the trade-off between increased cost and offsetting risk, and to optimize the new strategy in this regard;
- Adding a BC Clean resource would entail significant cost increases and may not be desired, while other options, such as purchasing “green tags”, could be economic and will be investigated;
- The peaking plant resource, as an alternative to short-term market purchases, is not recommended due to its increased cost; and
- These conclusions are supported under reasonable variations in load forecast, discount rates and market prices.

All told, on the basis of its Resource Plan FortisBC concludes that additional long-term firm resources are not needed until when and if the BC Hydro PPA expires, potentially in 2013. Further, FortisBC states that it should consider reducing its exposure to short-term market purchases (FortisBC Argument, p. 53).

FortisBC proposes the following Action Plan based on its conclusions (Ex. B-4, p. 74; FortisBC Argument, p. 53-54):

1. The Company will begin discussions with BC Hydro, with a view to gaining certainty regarding the status of the PPA beyond 2013.

2. The Company will conduct a more detailed study of a much shorter time frame than was assessed in this Resource Plan study, approximately five years, to optimize a new market strategy that provides more protection from market volatility and improved reliability. FortisBC comments that modeling the market is a complex undertaking and involves a variety of possible strategies and products that could be purchased. It contemplates that it may be possible that some combination of medium term purchases from Cominco and peaking purchase from others can provide a similar level of protection from market volatility and improved reliability at lower cost than the energy block purchases that were simulated in this Resource Plan.

3. The Company will update and file its DSM Potential Study and complete a new DSM plan covering the period 2005-2014, investigating whether a more aggressive program is more cost-effective.

4. The Company proposes to update its Resource Plan on a bi-annual basis. FortisBC states that it is essential that with the dependence on the market to meet some of its requirements, the Company needs to detect shifts in load growth and market trends as soon as possible in order to make the necessary adjustments to its resource plan.

5. The Company will investigate options other than addition of a new long-term firm clean resource for complying with the B.C. Energy Plan.

4.3 Submissions

FortisBC refers in argument to the following two issues raised in respect to its Resource Plan (FortisBC Argument, p. 54):

- Finalizing the PPA with BC Hydro for long term firm resources; and
- The proposed strategy to reduce exposure to market prices.

FortisBC is of the view that while there is risk associated with finalizing an agreement with BC Hydro, successful negotiations can be concluded prior to 2013 when the PPA is due to expire, FortisBC is optimistic that it won’t be a protracted negotiation given its prior experiences of working with BC Hydro (FortisBC Argument, p. 55).

FortisBC refers to its extensive analysis of the new market strategy to conclude that there is a reasonable likelihood of financial benefits to the customer by moving to a strategy that lessens exposure to the spot market. Because it recognizes that such a strategy is very sensitive to market factors, FortisBC proposes to conduct a more detailed study over a shorter time frame than was necessitated in its Resource Plan in order to optimize a strategy that provides more protection from market volatility and improved reliability (FortisBC Argument, pp. 55-56).

FortisBC submits that its Resource Plan is reasonable and prudent, meets the requirements of Section 45(6.2)(b) of the UCA, and is in the public interest (FortisBC Argument, p. 56; FortisBC Reply Argument, p. 28).

4.4 Commission Panel Determinations

The Commission Panel has reviewed the FortisBC Resource Plan, and all of the associated evidence adduced over the course of the hearing. **The Commission Panel accepts the Resource Plan, and component Action Plan,**

determining that it is reasonable and prudent, and that it meets the requirements of Section 45(6.2)(b) of the UCA and is in the public interest.

The Commission Panel has some concerns about the methodological framework that underpins the Resource Plan to the degree that the approach to explicitly account for uncertainty is not especially sophisticated. In one example, the Commission Panel determined that the conclusions of the Resource Plan are not robust to the impact on the new market strategy from changes to the sell back price of surplus energy. The Commission Panel appreciates that FortisBC recognizes that its Resource Plan could be improved in general with greater attention to sensitivity analysis, and in particular with a detailed study of a new market strategy over a shorter time horizon. The Commission Panel encourages FortisBC, both in the next iteration of its resource planning study and in the forthcoming study of a new market strategy, to provide a more comprehensive treatment of the uncertainty in its planning parameters. Besides expanding upon its sensitivity analyses, FortisBC could explore the potential of a simulation analysis, with the use of distributions around key input variables where possible, as a means to improve its accounting of uncertainty in its resource planning study.

With reference to FortisBC's proposed Action Plan, the Commission Panel supports the initiative to begin discussions with BC Hydro, with a view to gaining certainty regarding the status of the PPA beyond 2013. The Commission Panel recognizes that the results of the Resource Plan indicate that a sufficient window of time exists over which FortisBC can gain certainty on the status of the PPA before needing to consider other resource options. The Commission Panel requests that FortisBC file a status update on the progress of negotiations with BC Hydro at the same time as it files its next revenue requirements application, or sooner as applicable. The Commission Panel also requests that FortisBC file at that time a status update on the progress of its detailed study of a new market strategy, including preliminary results as relevant. As noted earlier in this Decision, the Commission Panel directs FortisBC to file its DSM potential study by June 30, 2005 and its 2005-2014 DSM Business Plan by October 31, 2005, the timelines proposed by FortisBC.

FortisBC proposes to update its Resource Plan on a bi-annual basis. In light of the results of the 2005 Resource Plan, the Commission Panel accepts this timeline for the next iteration of the Resource Plan, anticipating then that FortisBC will file an updated plan at the same time it files a 2007 Revenue Requirements application. However, the Commission Panel does not approve FortisBC's proposed timeline as a matter of policy in this instance. The Commission Panel will determine the timeline for any resource planning updates on a prospective basis with its review of future Resource Plans.

DATED at the City of Vancouver, in the Province of British Columbia, this 31st day of May 2005.

Original signed by:

L.F. Kelsey
Panel Chair and Commissioner

Original signed by:

P.G. Bradley
Commissioner

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Inc.
2005 Revenue Requirements,
2005-2024 System Development Plan and 2005 Resource Plan

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated December 14, 2004 and Order No. G-111-04 approving an interim rate increase effective January 1, 2005 and establishing the Regulatory Timetable for the review process
A-2	Letter dated December 18, 2005 providing information for the FortisBC Workshops and Pre-hearing Conference proceedings
A-3	Letter dated December 20, 2005 advising Participants that issues to be included on the Issues List will be discussed at the Pre-hearing Conference
A-4	Letter dated January 24, 2005 releasing Order No. G-14-05, the Issues List and the Amended Regulatory Timetable
A-5	Letter dated January 19, 2005 responding to Mr. Karow's January 9, 2005 submission (Exhibit C2-4)
A-6	Letter No. L-9-05 dated January 28, 2005 denying FortisBC's request for a Negotiated Settlement Process
A-7	Letter and Commission Information Request No. 1 dated January 28, 2005
A-8	Letter dated February 2, 2005 regarding Helmut Wartenberg's Information Request (Exhibit No. C8-3) to the Commission
A-9	Letter dated February 2, 2005 declining Mr. Karow's January 24, 2005 request to postpone the regulatory timetable and to post the Curriculum Vitae of Commission Board members and staff on the web (Exhibit No. C2-5)
A-10	Letter dated February 17, 2005 responding to Mr. Scarlett's letter of January 26, 2005 commenting on FortisBC's eligibility for the 2004 Incentive Payment
A-11	Letter and Order No. G-20-05 dated February 22, 2005 regarding the 2004 Incentive Adjustments

Exhibit No.	Description
A-12	Letter dated February 24, 2005 regarding the Oral Public Hearing location and start time
A-13	Letter and Commission Information Request No. 1 to the BC Old Age Pensioners Organization *et* al dated March 3, 2005
A-14	Letter to Registered Intervenors dated March 11, 2005 regarding whether they are supportive of the FortisBC Demand Side Management Technical Committee and the Load Forecast Technical Committee recommendations (Exhibit B-17 and B-18) with request to respond by March 16, 2005
A-15	Public Hearing Procedural Letter dated March 16, 2005
A-16	Letter dated March 17, 2005 accepting the recommendations of the Demand Side Management and Load Forecast Committees that there is no need to call hearing panels in the respective subject areas
A-17	Letter dated March 17, 2005 responding to Mr. Karow's e-mail of March 17, 2005 regarding Information Request's
A-18	Chart from FortisBC 2005 Revenue Requirements – Operations and Maintenance Costs (before Overheads capitalized)

APPLICANT DOCUMENTS

B-1	**FORTISBC INC.** 2005 Revenue Requirements Application dated November 26, 2004
B-2	FortisBC 2005-2024 System Development Plan submitted November 26, 2004
B-3	Notice of Counsel retainment dated December 16, 2004 from Dean O'Leary Farris, Vaughn, Wills & Murphy
B-4	Letter dated December 21, 2004 filing the 2005 Resource Plan (including Appendix D)
B-5	January 20, 2005 Workshop Presentation - 2005 Resource Plan
B-6	January 18 and 20, 2005 Workshop Presentation – System Development Plan (SDP) 2005-2024
B-7	January 21, 2005 Workshop Presentation – 2005 Revenue Requirements

Exhibit No.	Description
B-8	Letter dated January 27, 2005 requesting a revision to the Timetable and process for disposing of the Application
B-9	Letter dated January 31, 2005 replying to comments regarding the 2004 Incentive Program
B-10	Letter dated February 8, 2005 regarding Technical Committees
B-11	2004 Annual Review Powerpoint presentation dated January 20, 2005
B-12	Response dated February 18, 2005 to Commission Information Request No. 1 - (Note: Question 104 response includes attachment with original confidential report from PowerNex *Associates* Inc. for which FortisBC Inc. has provided authorization to now release as non-confidential)
B-12A	Excel spreadsheet files from Exhibit B-12 (CD)
B-13	Response dated February 18, 2005 to The BC Old Age Pensioners Organization *et al.* Information Request No. 1
B-14	Responses dated February 18, 2005 to Information Request No. 1 from the following: IMEU Han Karow Kootenay-Okanagan Electric Consumers Association Natural Resource Industries Alan Wait Helmut Wartenberg
B-15	Letter dated February 24, 2005 requesting that FortisBC Inc. be exempted from the requirement of filing the March 1, 2005 report on transition activities
B-16	Letter and Information Request No. 1 dated March 4, 2005 to the BC Old Age Pensioners Organization
B-17	Letter dated March 9, 2005 and Report of the Demand Side Management Technical Committee
B-18	Letter dated March 9, 2005 and Report of the Load Forecast Technical Committee
B-19	Letter dated March 10, 2005 and revisions to 2005 Revenue Requirements Application
B-20	Letter dated March 11, 2005 and Report of the Capital Additions Technical Committee

Exhibit No.	**Description**
B-21	Letter dated March 11, 2005 and Report of the Power Purchase Technical Committee
B-22	Letter and Witness Panels dated March 16, 2005
B-23	Letter dated March 15, 2005 and the FortisBC Semi-Annual Demand Side Management Report in response to Commission Information Request 111
B-24	Letter dated March 18, 2005 filing Errata to FortisBC's Information Responses filed February 18, 2005 (Exhibit B-14)
B-24A	Final Errata Page – Response to Karow Information Request No. 1
B-25	Letter dated March 18, 2005 filing a Revised 2005 Revenue Requirements Application ("Second Revised Application")
B-26	Letter dated March 22, 2005 filing a Revised 2005 Revenue Requirements Application ("Third Revised Application")
B-27	Undertaking: Panel 2 – Transcript Page 134, lines 22-26
B-28	Undertaking: Panel 2 – Transcript Page 152, lines 20-26
B-29	Undertaking: Panel 2 – Transcript Page 168, lines 6-8
B-30	Undertaking: Panel 2 – Transcript Page 182, lines 12-15
B-31	Undertaking: Panel 2 – Transcript Page 183, lines 4-5
B-32	Undertaking: Panel 2 – Transcript Page 187, lines 9-21
B-33	Undertaking: Panel 3 – Transcript Page 205, line 5 to Page 206, line 24
B-34	Undertaking: Panel 3 – Transcript Page 208, lines 1-22
B-35	Undertaking: Panel 3 –Transcript Page 218, lines 8-26 and Page 219, lines 1-25

Exhibit No.	Description
B-36	Undertaking: Panel 3 – Transcript Page 219, lines 16 and 17
B-37	Corrected version of Exhibit C5-9
B-38	Undertaking: Panel 3 – Transcript Page 306, lines 25-26, and Page 307, lines 1-3
B-39	Undertaking: Panel 3 – Transcript Page 309, lines 13-15
B-40	Undertaking: Panel 3 – Transcript Page 312, lines 13-16
B-41	Undertaking: Panel 3 – Transcript Page 313, lines 12-14 and lines 17-18
B-42	Undertaking: Panel 3 – Transcript Page 318, lines 1-3
B-43	Undertaking: Panel 3 – Transcript Page 322, lines 22-25
B-44	Undertaking: Panel 3 – Transcript Page 325, lines 25-26
B-45	Undertaking: Panel 3 – Transcript Page 327, lines 3-4
B-46	Undertaking: Panel 3 – Transcript Page 374, lines 15-22
B-47	Undertaking: Panel 3 – Transcript Page 376, lines 13-26, and Page 377, lines 1-5
B-48	Undertaking: Panel – Transcript Page 385, lines 24-26, and Page 386, lines 1-2
B-49	Undertaking: Panel 3 – Transcript Page 393, lines 10-14
B-50	Undertaking: Panel 4 – Transcript Page 437, lines 24-26
B-51	Undertaking: Panel 4 – Transcript Page 445, lines 1-7

Exhibit No.	Description
B-52	Undertaking: Panel 4 – Transcript Page 493, line 26, and Page 494, lines 1-3
B-53	Undertaking: Panel 6 – Transcript Page 512, lines 23-26, and Page 513, lines 1-8
B-54	FortisBC Management Discussion and Analysis dated February 3, 2005 regarding Three Months and Twelve Months Ended December 31, 2004 compared to Three Months and Twelve Months Ended December 31, 2003
B-55	Booth Evidence – Recalculation of Interest Coverage Ratios (Summary)
B-56	Evidence, dated June 1996, of Laurence D. Booth and Michael K. Berkowitz on Capital Structure and Fair Return before the Alberta Energy and Utilities Board in the Alberta Electric Utilities 1996 Tariff Applications
B-57	Excerpt, dated April 13, 1994, from Volume 7, Page 1183 of the BC Gas Utility Ltd., West Kootenay Power Ltd., and Pacific Northern Gas hearing process on the Rates of Return on Common Equity
B-58	Excerpt from FortisAlberta & FortisBC – British Columbia – Your Bill (Bill Insert)
B-59	Undertaking: Panel 4 – Transcript Page 493, line 26, and Page 494, lines 1-3, and Page 495, lines 8-10
B-60	Undertaking: Panel 5 – Transcript Page 668, lines 20-23
B-61	Undertaking: Panel 5 – Transcript Page 673, lines 14-15
B-62	Undertaking 29: Panel 6 - Transcript Page 819, lines 16-20
B-63	Undertaking 30: Panel 6 - Transcript Page 820, lines 14-18
B-64	Undertaking 31: Panel 6 - Transcript Page 821, lines 25-26, and Page 822, line 1
B-65	Undertaking 32: Panel 6 - Transcript Page 826, lines 17-26, and Page 827, lines 1-21
B-66	Undertaking 33: Panel 6 - Transcript Page 828, lines 20-26, and Page 829, lines 1-8

Exhibit No.	Description
B-67	Undertaking 34: Panel 6 - Transcript Page 829, lines 14-26, and Page 830 lines 1-19
B-68	Undertaking 35: Panel 6 - Transcript Page 831, lines 1-26, and Page 832 lines 1-4
B-69	Undertaking 36: Panel 6 - Transcript Page 833, lines 12-14
B-70	Undertaking 37: Panel 6 - Transcript Page 833, lines 23-26, and Page 834, lines 1-3
B-71	Undertaking 38: Panel 6 - Transcript Page 834, lines 10-12
B-72	Undertaking 39: Panel 6 - Transcript Page 835, lines 10-13
B-73	Undertaking 40: Panel 6 - Transcript Page 847, lines 12-14
B-74	Undertaking 41: Panel 6 - Transcript Page 850, lines 6-10
B-75	Undertaking 42: Panel 6 - Transcript Page 851, lines 26, and Page 852, line 3
B-75A	Letter dated April 13, 2005 regarding correction to Undertaking (Exhibit B-75)
B-76	Undertaking 43: Panel 6 - Transcript Page 854, lines 25-26, Page 855, 1-15
B-77	Undertaking 44: Panel 6 - Transcript Page 860, lines 8-21
B-78	Undertaking 45: Panel 6 - Transcript Page 861, lines 12-13
B-79	Undertaking 46: Panel 6 - Transcript Page 874, lines 3-7
B-80	Undertaking 47: Panel 6 - Transcript Page 878, lines 20-26 and Page 879, lines 3-4
B-81	Undertaking 48: Panel 6 - Transcript Page 883, lines 14-26 from March 24, 2005

Exhibit No.	**Description**
INTERVENOR DOCUMENTS	
C1-1	**KOOTENAY-OKANAGAN ELECTRIC CONSUMERS ASSOCIATION** – Notice of Intervention dated November 30, 2004 from Donald Scarlett
C1-2	Letter dated January 26, 2005 commenting on FortisBC's eligibility for the 2004 Incentive Payment
C1-3	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C1-4	Table – Actual and Allowed ROE
C2-1	**KAROW, HANS** – Notice of Intervention dated December 2, 2004
C2-2	Letter dated December 27, 2004 regarding Mr. Karow's interim submission
C2-3	Letter dated January 3, 2005 filing Mr. Karow's follow-up submission
C2-4	E-mail dated January 9, 2005 – Follow-up submission with respect to his January 3, 2005 and December 27, 2004 filings
C2-5	Email dated January 24, 2005 enclosing a further follow-up to the January 3, 2005 and December 27, 2004 submission and information request
C2-6	Information Request dated February 2, 2005 to FortisBC Inc.
C2-7	E-mail dated March 17, 2005 regarding general information request
C3-1	**WAIT, ALAN** – Notice of Intervention dated December 7, 2004
C3-2	Letter dated January 27, 2005 commenting on FortisBC's eligibility for the 2004 Incentive Payment
C3-3	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C3-4	Excerpt from Waneta HydroElectric Expansion Project Report
C3-5	2004 Revenue Requirements - Appendix A to Order No. G-38-04 – Page 11 of 27 dated March 3, 2004

Exhibit No.	Description
C4-1	**NATURAL RESOURCE INDUSTRIES** – Notice of Intervention dated December 7, 2004 from Richard Tarnoff
C4-2	E-mailed dated January 28, 2005 regarding whether FortisBC Inc. should receive an incentive for 2004
C4-3	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C4-4	Letter dated February 3, 2005 advising that Richard Tarnoff will also be representing Hedley Improvement District
C5-1	**THE BC OLD AGE PENSIONERS ORGANIZATION *ET AL*.** – Notice of Intervention dated December 16, 2004 from Richard Gathercole
C5-2	Letter dated January 24, 2005 confirming availability of BCOAPO's witness, Mr. Lawrence Booth
C5-3	Letter dated January 27, 2005 commenting on FortisBC's eligibility for the 2004 Incentive Payment
C5-4	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C5-5	Evidence of Laurence Booth filed February 25, 2005
C5-6	Letters and responses dated March 11, 2005 to Commission Information Request No. 1 and FortisBC Inc. Information Request No. 1
C5-6A	Detailed information regarding Information Request responses to Exhibit C5-6 (CD)
C5-7	Letter dated March 14, 2005 responding to Commission letter of March 11, 2005 regarding support of FortisBC Inc.'s Technical Committees recommendations (Exhibit A-14)
C5-8	Witness aid, headed "Background", with chart
C5-9	Table – Percentage deviation of actuals from forecast loads for each group and the average over the period 1995-2003
C6-1	**COLUMBIA POWER CORPORATION** – Notice of Intervention dated December 23, 2004

Exhibit No.	**Description**
C7-1	**SLACK, BURYL** – Notice of Intervention dated December 30, 2004
C8-1	**WARTENBERG, HELMUT** – Notice of Intervention dated January 4, 2005
C8-2	Letter dated January 18, 2005 citing concerns and summary requests
C8-3	Information Request No. 1 dated January 27, 2005 to the British Columbia Utilities Commission
C8-4	Information Request No. 1 dated February 1, 2005 to FortisBC
C9-1	**TERASEN GAS INC.** – Notice of Intervention dated January 5, 2005 from Scott Thomson
C10-1	**INTERIOR MUNICIPAL ELECTRICAL UTILITIES (IMEU)** – Notice of Intervention dated January 5, 2005 from R.E. Carle
C10-2	Letter dated January 12, 2005 from Christopher P Weafer, Owen·Bird advising that he has been retained as counsel for the IMEU
C10-3	Letter dated January 27, 2005 commenting on FortisBC's eligibility for the 2004 Incentive Payment
C10-4	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C10-5	E-mail dated March 17, 2005 in response to H. Karow e-mail of March 17, 2005 (Exhibit C2-7)
C11-1	**POWERHOUSE DEVELOPMENTS INC.** – Notice of Intervention dated January 5, 2005 from W.P. Harland
C12-1	**GLACIER POWER BC LTD.** - Notice of Intervention dated February 7, 2005 from Neil Murphy

Exhibit No.	Description
INTERESTED PARTY DOCUMENTS	
D-1	Renninger, Bud – Web registration received January 6, 2005
D-2	Web registration dated February 7, 2005 from Neil Murphy, Glacier Power BC Ltd. requesting Interested Party status – **WITHDRAWN** – Changed to Intervenor Status
LETTERS OF COMMENT	
E-1	Letter of Comment dated December 14, 2004 from Robb Mayes
E-2	Letter of Comment dated December 14, 2004 from David Egli
E-3	Letter of Comment received December 15, 2004 from Elkink Ranch Ltd.
E-4	Letter of Comment dated December 15, 2004 from Ron Planiden
E-5	Letter of Comment dated December 31, 2004 from Ken Hoffman and Lori Robertson
E-6	Letter of Comment dated December 31, 2004 from Derrick M. May, P.Eng.
E-7	Letter of Comment dated January 3, 2004 from R.C. Cassan
E-8	Letter of Comment dated December 25, 2004 from James Johnston
E-9	Letter to the Editor, Castlegar News dated January 6, 2005 from Marilyn Idle
E-10	Letter of Comment received January 7, 2005 from Tom Stanley
E-11	Letter to the Editor dated January 4, 2005 from Ed Chenail
E-12	Letter of Comment dated January 13, 2005 from Van Quaia
E-13	Letter of Comment dated January 19, 2005 from John Slater, Mayor, Town of Osoyoos
E-14	E-mail from Robert Hobbs, Chair, BCUC providing clarification on two points contained in Ms. Idle's Letter to the Editor of the Castlegar News (Exhibit E-9)
E-15	Letter of Comment dated February 3, 2005 from David Pehota

Exhibit No.	Description
E-16	Letter of Comment dated February 9, 2005 from Elizabeth Strong
E-17	Letter of Comment dated February 21, 2005 from Helen Kennedy
E-18	Letter of Comment dated February 24, 2005 from Donna Krane

Pacific Northern Gas Ltd. Project No. 3698411 – Order No. G-134-05, 2006 Revenue Requirements Application

ROBERT J. PELLATT
COMMISSION SECRETARY
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Log No. 12700

VIA E-MAIL
cdonohue@png.ca

August 21, 2006

Mr. C.P. Donohue
Director, Regulatory Affairs & Gas Supply
Pacific Northern Gas Ltd.
950 - 1185 West Georgia Street
Vancouver, B.C. V6E 4E6

Dear Mr. Donohue:

Re: Pacific Northern Gas Ltd. ("PNG")
Project No. 3698411 – Order No. G-134-05
2006 Revenue Requirements Application

Further to your Application for approval of PNG's 2006 Revenue Requirements, we enclose Commission Order No. G-99-06 with Reasons for Decision.

Yours truly,

Original signed by:

Robert J. Pellatt

RJP/cms
Enclosure
cc Registered Intervenors & Interested Parties
PNGW-2006RR

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-99-06

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Application by Pacific Northern Gas Ltd.
(PNG-West and Granisle)
for Approval of 2006 Rates

BEFORE: L.A. Boychuk, Panel Chair
and Commissioner

August 16, 2006

O R D E R

WHEREAS:

A. On November 30, 2005, Pacific Northern Gas Ltd. (“PNG”, “PNG-West” and “Granisle”) filed for approval of its 2006 Revenue Requirements Application (the “Application”) to amend its rates on an interim and final basis, effective January 1, 2006, pursuant to sections 89 and 58 of the Utilities Commission Act (the “Act”); and

B. The Application proposes to increase delivery rates to all customers, except Methanex Corporation (“Methanex”) and West Fraser-Kitimat (“West Fraser”), as a result of decreases in cost of service and decreased deliveries to most customer classes. Methanex and West Fraser have contracts in place that provide for fixed demand charges over the term of the contracts; and

C. Methanex closed its methanol/ammonia complex in Kitimat in November 2005 and the Methanex contract terminated effective March 1, 2006 (“Methanex closure”). PNG’s 2006 margin forecast includes fixed demand charges for January and February 2006 under the terms of the Methanex contract; and

D. In its Application PNG forecasts a 2006 revenue deficiency of approximately $5.2 million, which is mainly due to a reduction in revenues of approximately $10.4 million resulting from the Methanex closure. This revenue reduction is partly offset by PNG crediting to its cost of service $5.6 million from the contract termination payment of $23.3 million that Methanex paid to PNG on February 28, 2006; and

E. Following consideration of submissions on the review process for the Application the Commission, by Order No. G-134-05 dated December 16, 2005, scheduled an Negotiated Settlement Process (“NSP”) for the review of the PNG Application and established a Regulatory Timetable as proposed by PNG and supported by the BC Old Age Pensioners Organization et al. (“BCOAPO”); and

…/2

F. Order No. G-134-05 also approved for PNG an interim refundable rate increase in the delivery rates for all classes of customers as filed in the Application effective January 1, 2006, except Methanex and West Fraser. That Order also approved permanent Gas Supply Cost Recovery Rates for sales service customers effective January 1, 2006. The Order also approved the PNG-West company use rate of $0.305/GJ as an interim rate effective January 1, 2006; and

G. The Negotiated Settlement discussions were held in Vancouver on March 13 to 15, 2006 and a proposed Settlement Agreement that would reduce PNG's revenue deficiency to $4.091 million was circulated on March 31, 2006 to the Intervenors and PNG for comments; and

H. Following a review of the comments on the proposed Settlement Agreement, the Commission Panel considered that a further process should be established to review and consider Item 1, "Methanex Termination Payment" of the proposed Settlement Agreement. Accordingly, by Order No. G-40-06 dated April 7, 2006, the Commission approved a BCOAPO request for an additional round of information requests and established a timetable for information requests, information responses, submissions by PNG, Intervenor submissions and a PNG reply; and

I. By Letter No. L-19-06 dated May 17, 2006, the Commission Panel sought further specific written submissions from those parties who had submitted written argument based on the evidentiary record established in this proceeding. Letter No. L-19-06 contained Commission Panel questions and established a timetable for written responses by PNG and BCOAPO to questions relating to their submissions, the filing of a response by BCOAPO and Mr. Childs and a reply by PNG. The Commission Panel indicated that it would consider the additional submissions based on the evidentiary record for this proceeding prior to making a decision on PNG's Revenue Requirements Application and the proposed Settlement Agreement; and

J. The Commission Panel reviewed the submissions made by PNG, BCOAPO and Mr. Childs, the proposed Settlement Agreement for PNG-West and the letters of comment received from the Intervenors. The Commission Panel determined that in view of the position of BCOAPO, the Commission Panel did not have a proposed Settlement Agreement before it for approval and it therefore was not in a position, as outlined in Order No. G-66-06 dated June 9, 2006 and the attached Reasons for Decision, to render a decision without further process, including a decision in relation to Item 1 of the proposed Settlement Agreement; and

K. By Order No. G-66-06 the Commission Panel also concluded that before establishing a further process, the views of parties must be obtained in an effort to establish the most effective and efficient process possible at that stage. Order No. G-66-06 established a timetable for the filing of comments by BCOAPO and other registered intervenors and PNG reply comments, including submissions on appropriate steps and timing for either an oral and/or written hearing process, the issues to be considered, confirmation of the issues that may have been resolved during the NSP, and the nature of any evidence to be filed and justification therefore; and

L. The Commission Panel reviewed the submissions made by PNG, BCOAPO and Mr. Childs and, by Order No. G-77-06 dated June 28, 2006, closed the evidentiary record and established a timetable for the filing of Argument with PNG's Argument required by July 7, 2006, Intervenor Argument by July 17, 2006 and PNG Reply Argument by July 24, 2006; and

…/3

M. The Commission Panel has considered the Application, the evidence adduced in relation thereto, the submissions and Written Argument, all as set forth in the Reasons for Decision attached as Appendix A and issued concurrently with this Order.

NOW THEREFORE pursuant to Sections 58, 60 and 61 of the Act the Commission orders as follows:

1. The Commission approves for PNG its Application subject to the required adjustments set out in the attached Reasons for Decision.

2. Since the approved rates are less than the interim rates that have been in effect since January 1, 2006, PNG is to inform its customers of the final rates by way of a Customer Notice and provide a method for refunding excess payments back to customers.

3. PNG is to file permanent Gas Tariff Rate Schedules that are in accordance with the terms of this Order and Reasons for Decision.

4. PNG is to file a complete set of detailed schedules contained under Tab Rates and Tabs 1 to 5 of the Application that reflects the adjustments required by this Order and Reasons for Decision, by September, 8, 2006.

DATED at the City of Vancouver, in the Province of British Columbia, this 21st day of August 2006.

BY ORDER

Original signed by:

L.A. Boychuk
Panel Chair and Commissioner

Attachment

An Application by Pacific Northern Gas Ltd.
(PNG-West and Granisle)
for Approval of 2006 Rates

REASONS FOR DECISION

1.0 THE APPLICATION

On November 30, 2005, Pacific Northern Gas Ltd. ("PNG", "PNG-West" and "Granisle") filed for approval of its 2006 Revenue Requirements Application (the "Application") to amend its rates on an interim and final basis, effective January 1, 2006, pursuant to sections 89 and 58 of the Utilities Commission Act (the "Act"). The Application proposed to increase delivery rates to all customers, except Methanex Corporation ("Methanex") and West Fraser-Kitimat ("West Fraser"), as a result of decreases in cost of service and decreased deliveries to most customer classes. Methanex and West Fraser have contracts in place that provide for fixed demand charges over the term of the contracts.

Methanex closed its methanol/ammonia complex in Kitimat in November 2005 and the Methanex contract terminated effective March 1, 2006 ("Methanex closure"). PNG's 2006 margin forecast includes fixed demand charges for January and February 2006 under the terms of the Methanex contract. In its Application, PNG forecast a 2006 revenue deficiency of approximately $5.2 million, which is mainly due to a reduction in revenues of approximately $10.4 million resulting from the Methanex closure. This revenue reduction is partly offset by PNG crediting to its cost of service $5.6 million from the contract termination payment of $23.3 million that Methanex paid to PNG on February 28, 2006.

On February 17, 2006 PNG revised the Application to reflect 2005 year-end actual results and to include updates to customer counts, use per account and reclassification of customers, which reduced the 2006 revenue deficiency to $4.034 million (Exhibit B-10). On March 9, 2006, PNG advised the Commission and Registered Intervenors that the Commission's decision to increase the 2006 benchmark low-risk utility return on equity to 8.80 percent by Order No. G-14-06 dated March 2, 2006, would increase PNG's allowed return on common equity under the Commission's automatic adjustment formula from 8.94 percent to 9.45 percent and increase PNG's 2006 revenue deficiency to $4.435 million (Exhibit B-13).

2.0 THE REGULATORY PROCESS

PNG had discussions regarding the review process for the Application with the BC Old Age Pensioners Organization et al. ("BCOAPO") and staff of the Ministry of Energy, Mines and Petroleum Resources, who were the active intervenors in the review of the PNG 2004 and 2005 revenue requirements applications (the "Parties"). By letter dated December 13, 2005, PNG advised the Commission that the Parties were of the view that the Application should be subject to a Negotiated Settlement Process ("NSP") and provided a draft Regulatory Timetable for information requests, information responses, a 2005 year-end update to the Application and NSP discussions commencing the week of March 13, 2006 (Exhibit B-2). The draft Regulatory Timetable did not include a provision for Intervenor evidence and related information requests and responses. On December 14, 2005 BCOAPO filed a letter of support for a NSP and PNG's proposed Regulatory Timetable (Exhibit E-1).

By Order No. G-134-05 dated December 16, 2005 (Exhibit A-1), the Commission approved for PNG an interim refundable rate increase in the delivery rates for all classes of customers as filed in the Application effective January 1, 2006, except Methanex and West Fraser. Order No. G-134-05 also scheduled an NSP for the review of the PNG Application and established a Regulatory Timetable for information requests and information responses with NSP discussions to commence on March 13, 2006 as proposed by PNG and supported by BCOAPO.

During the course of this process, the Commission also received numerous letters of comments and form letters expressing concern about the proposed rate increase and a petition containing over 4,000 signatures (Exhibit C11-4) that also opposed the Application.

3.0 THE PROPOSED SETTLEMENT AGREEMENT

The NSP discussions were held in Vancouver on March 13 to 15, 2006. The following Intervenors participated: BCOAPO, Robin Austin, MLA-Skeena, Mayor Talstra of Terrace, Neil Helland and counsel for the Haisla Nation. Following the conclusion of the negotiations, a proposed Settlement Agreement that would reduce PNG's revenue deficiency to $4.091 million was circulated to those who participated in the settlement discussions. By letter dated March 28, 2006, PNG advised the Commission that the final copies of the proposed Settlement Agreement and letters of comment would be forwarded to the Commission for review and made public on March 31, 2006. PNG's letter asked the Commission to issue an order approving the proposed Settlement Agreement on an interim or permanent basis by April 7, 2006 to coincide with the Gas Supply Cost Recovery Rates that were approved effective April 1, 2006. The letter also advised that "one of the parties may be making a request to have one matter dealt with by the Commission that would not change the overall 2006 cost of service agreed to for the PNG-West division". The proposed Settlement Agreement included Bill Comparison Tables for residential and small commercial customers, which indicated that the proposed rates for delivery charges and gas supply cost recovery rates effective April 1, 2006, would be less than the rates that prevailed at the end of 2005.

Letters of comment on the proposed Settlement Agreement were received from the BCOAPO, the Haisla Nation, Robert W. Childs, Mayor Talstra of Terrace, Robin Austin, MLA-Skeena and the Kitimat Chamber of Commerce. In its letter of comment dated March 29, 2006, BCOAPO advised that it did not accept the proposed Settlement Agreement and in particular Item 1 which "represents the fundamental gist of the agreement in that it purports to transfer the entire shortfall arising from Methanex leaving the PNG-West system to the residential and small commercial customers". BCOAPO stated that it did not have any objection to the remainder of the proposed Settlement Agreement and had no objection to PNG's request to have the rates that would arise from the proposed Settlement Agreement approved on an interim basis, pending resolution of the allocation of the Methanex revenue shortfall. In the letter, BCOAPO expressed its position as follows: "[It] is BCOAPO's position that the question of the proper allocation of the revenue shortfall arising from Methanex leaving the PNG-West system should properly be addressed by a Commission panel and should not be the subject of a negotiated settlement." BCOAPO also expressed the view that an oral hearing and a full 2006 Revenue Requirements proceeding was not necessary. It suggested that the issue could be resolved in a written hearing process with an additional round of information requests to PNG-West to ensure that all necessary and appropriate evidence is before the Commission.

Robert Childs' comments were similar to those of BCOAPO, except that he recommended that "the 06/01/01 Interim Rates remain in effect until a Final Commission Ruling is made". The Haisla Nation accepted PNG's commitment to work with the Haisla Nation and took no position on the remainder of the proposed Settlement Agreement. Mayor Talstra in his letter of comment dated April 5, 2006, found the proposed Settlement Agreement to be acceptable provided that the new rates, including gas supply costs charges remain in effect throughout 2006. In his letter dated April 6, 2006, Robin Austin did not agree with PNG's proposal that the lost revenue from the Methanex contract should be downloaded to residential and commercial customers and requested a written hearing to resolve this issue. The Kitimat Chamber of Commerce in its email dated April 6, 2006 protested PNG's increased delivery charges and asked for the review process to continue.

By letter dated April 3, 2006, PNG requested that the Commission approve rates arising from the proposed Settlement Agreement on either a permanent basis or on an interim basis pending review of the issue raised in BCOAPO's letter of comment dated March 29, 2006. In support of its request that the Commission approve the 2006 NSP rates on a permanent basis, PNG cited previous Commission decisions on the allocation of revenue reductions to PNG's customers and suggested that by allocating the revenue reduction to the remaining customers, the Commission would carry out its statutory duty consistent with past practice. PNG further submitted that allocating any of the remaining revenue deficiency to PNG's shareholders would contravene section 59(5)(b) of the Act. PNG recommended that the Commission issue an Order on April 7, 2006 reconfirming its past practice and approving the NSP 2006 rates on a permanent basis. In the alternative, PNG submitted that should the Commission decide to conduct a hearing as requested by BCOAPO, then the BCOAPO "has effectively become the applicant in this situation" and should be directed to file evidence upon which all parties should be given an opportunity to issue information requests to BCOAPO.

By letter dated April 4, 2006, BCOAPO commented on PNG-West's brief review of past Commission decisions and submitted that the question of how section 59 of the Act should be applied in PNG-West's current situation is a matter that requires determination by the Commission after hearing submissions from appropriate parties. BCOAPO agreed that the record was "essentially complete". While it did not propose to adduce further evidence, BCOAPO did request further Commission process on the main issue, including a round of information requests to ensure that relevant information, which was not included in the formal record but referred to in the course of the NSP by PNG, became part of the public record.

The BCOAPO letter concluded with the comment: "In BCOAPO's submission, its suggested process would result in a more focused and efficient consideration of the main issue than that proposed by PNG-West in its April 13, 2006 letter".

The Commission reviewed the proposed Settlement Agreement for PNG-West and the letters of comment received. It accepted the BCOAPO request for a further process. By Order No. G-40-06, the Commission established a process to review and consider Item 1, "Methanex Termination Payment", of the proposed Settlement Agreement. Order No. G-40-06 provided for an additional round of Intervenor information requests to PNG-West and set a filing deadline for Intervenor requests of April 18, 2006 with a PNG information response deadline of April 24, 2006. The Commission did not agree with PNG-West's characterization of BCOAPO as an effective applicant in this situation and, accordingly, the Commission did not direct BCOAPO to file evidence. Order No. G-40-06 also set a timetable for submissions related to Issue 1 with a PNG filing deadline of April 28, 2006, followed by Intervenor submissions of May 4, 2006 and a PNG Reply of May 9, 2006.

4.0 SUBMISSIONS ON ITEM 1 OF THE PROPOSED SETTLEMENT AGREEMENT

PNG filed its submission on April 28, 2006. PNG stated in its April 28, 2006 submission that: "…there is a statutory obligation upon the Commission to fix rates that permit PNG the opportunity to recover all of its costs of providing service, including the fair rate of return on common equity approved for PNG by the Commission. Rates that are insufficient to enable a utility to recover its cost, including a fair and reasonable return, are unjust and unreasonable under the Utilities Commission Act". PNG cited as the leading case authority ***Hemlock Valley Electrical Services v. British Columbia (Utilities Commission)*** (1992), 66 B.C.L.R (2d) 1 (C.A.) which, in turn, is based on the Supreme Court of Canada's decision in ***British Columbia Electric Railway Co. Ltd. v. Public Utilities Commission of BC***, [1960] S.C.R. 837 (***"Hemlock Valley"* and *"B.C. Electric"***, respectively). In PNG's view these decisions focus on what are now substantially the provisions found in subsections 59(1), (4), (5) and 60(1) of the Act (PNG April 28, 2006 submission, paragraphs 4-12).

PNG also referred to the Commission's findings in the 2002 PNG Revenue Requirements Decision with respect to a 2002 revenue reduction from the methanol plant shutdown in 2001 and a new negotiated agreement with Methanex (the "2002 Decision"). The 2002 Decision noted that the allocation of the revenue deficiency from Methanex to the other customers is consistent with previous actions of the Commission. The 2002 Decision also found that rates to all customer classes remained affordable at that time (PNG April 28, 2006 submission, paragraph 17).

The BCOAPO filed its Reply Argument on May 4, 2006. BCOAPO agreed that ***Hemlock Valley*** and ***B.C. Electric*** are applicable to the regulation of utilities in British Columbia; however, it submitted that the Commission must consider how these decisions should be applied to a utility in PNG's situation. BCOAPO quotes from the judgment of Mr. Justice Martland in ***B.C. Electric*** which states in part, "The rate to be imposed [under what is now section 60 of the Act having regard to what are now subsections 59(5)(a) and (b) of the Act] shall be neither excessive for this service nor insufficient to provide a fair return on rate base. There must be a balancing of interests." BCOAPO further submitted that ***Hemlock Valley*** and ***B.C. Electric*** must be considered in the light of ***ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)***, 2006 SCC 4 ("***ATCO***"). BCOAPO argues that the Supreme Court in Canada in ***ATCO*** "…has appropriately set out a balance between shareholders and ratepayers in the allocation of the revenue requirement shortfall that the utility faces" and urges the Commission to follow the approach in ***ATCO*** (BCOAPO May 4, 2006 submission, paragraphs 27-38).

BCOAPO concluded its submission as follows:

> 45. For all these reasons BCOAPO submits that approval of Item 1 of the Settlement Agreement would result in rates to residential customers which are not just and reasonable.
>
> 46. The Commission should not approve Item 1 of the Settlement Agreement.

Mr. Childs also filed a submission on Item 1. He expressed the view that the remaining customers should not be solely responsible for the revenue shortfall arising from the Methanex closure. At the end of his submission, he made the following suggestions:

> (1) PNG recover 100% of their audited costs to physically supply gas to customers.
>
> (2) The rest of the Methanex closure shortfall should be shared equally between the PNG shareholders and the remaining customers, provided that the gas delivery charge does not exceed:
>
> (i) the existing proposed average increases in Hydro, ICBC insurance rates or property taxes.
> (ii) the cost of inflation by more than 100%.

PNG filed its Reply Submission on May 9, 2006. It noted that with the exception of Item 1, all other aspects of the proposed Settlement Agreement had been agreed to by the Parties. PNG took issue with a number of the factual assertions made by the BCOAPO, distinguished ***ATCO*** on the basis that ***ATCO*** did not involve the setting of just and reasonable rates and submitted that ***Hemlock Valley*** and ***B.C. Electric*** remain the governing law, noting that ***Hemlock Valley*** was cited with approval recently in ***TransCanada Pipelines Ltd. v. Canada (National Energy Board)***, [2004] FCA 149.

PNG also took issue with Mr. Childs' submissions relating to the interpretation of sections 59 and 60 of the Act and submitted that a number of Mr. Childs' submissions were inaccurate or irrelevant. PNG concluded its Reply as follows:

> 25. To allocate any of the net revenue deficiency resulting from the termination of the Methanex contract to PNG's shareholders, as advocated by BCOAPO and Mr. Childs, would result in rates that do not permit PNG to recover its costs of providing service and would therefore contravene sections 59 and 60 of the Utilities Commission Act.
>
> 26. PNG reiterates its request that the Commission approve the March 15, 2006 Settlement Agreement in its entirety, including Item 1.

By Letter No. L-19-06, the Commission Panel sought further specific written submissions from those parties who had submitted written argument based on the evidentiary record established in the proceeding. Letter No. L-19-06 contained Commission Panel questions and requested that PNG and BCOAPO, as appropriate, file further written responses that relate to their written submissions, by Monday, May 29, 2006 and that BCOAPO and Mr. Childs, if he so wished, file a response by Friday, June 2, 2006, followed by a PNG reply by Wednesday, June 7, 2006. The Commission Panel indicated that it would consider these additional submissions based on the evidentiary record for the proceeding prior to making a decision on PNG's Revenue Requirements Application and the proposed Settlement Agreement.

5.0 RESPONSES TO LETTER NO. L-19-06 AND SUBMISSIONS

PNG, BCOAPO, and Mr. Childs all responded to the questions in Letter No. L-19-06 within the times provided. The Commission Panel only intends to refer here to certain answers of BCOAPO and the PNG reply to those answers. In response to Question 1 ["Is it the fact that parties have agreed to all aspects of the proposed Settlement Agreement, but for Item 1, that brings ***Hemlock Valley*** into operation?"], BCOAPO's response was "No". It stated that Item 1 was "clearly the major [d]river of the proposed revenue requirement increase" that other items were secondary and that by agreeing to those other items the Parties could avoid a full hearing into all aspects of the Application and focus on the major issue. Significantly, BCOAPO stated that "…the evidentiary record in this proceeding is not sufficient to allow the Commission to make an appropriate apportionment between the remaining ratepayers and PNG's shareholders of the revenue deficiency resulting from Item 1". It submitted that evidence with respect to the appropriate return on equity risk premium for PNG post-Methanex and on the methodology for determining an appropriate allocation of the revenue deficiency is now required (BCOAPO Response, May 29, 2006, pp. 1 and 2).

In partial response to Question 5 in Letter No. L-19-06 ["…the Commission remains unclear and seeks clarification related to the level of apportionment that BCOAPO suggests would be appropriate, the principles or methodology BCOAPO suggested should be applied, and the evidentiary basis on the record of this proceeding upon which BCOAPO relies to allow the Commission to do so."], after stating its position that there is no proposed Settlement Agreement before the Commission for approval, BCOAPO submitted that once the Commission has made its decision on Item 1, the NSP should reconvene and:

> If a Settlement Agreement is reached it would then be presented to the Commission for approval. If no Settlement Agreement is reached the matter would then proceed to an appropriate hearing or, alternatively, it would be open to PNG to amend its application.

The BCOAPO once again submitted in its response to Question 5 that there is an insufficient evidentiary record before the Commission to make a decision (BCOAPO Response May 29, 2006, p. 2) and in paragraph 1 of its response dated June 2, 2006, BCOAPO reiterated its position that there is no proposed Settlement Agreement before the Commission at this time.

In its Reply Submission dated June 6, 2006, PNG addresses BCOAPO's most recent submissions on the absence of a settlement and the need for further evidence and process. In paragraph 7 of its Reply under the heading **"BCOAPO's Shifting Position"**, PNG provides the following summary of the BCOAPO position prior to May 29, 2006**:**

> 7. Prior to its May 29, 2006 filing, BCOAPO's position can be summarized in its own words as follows:
>
> (a) BCOAPO "does not accept Item 1 of the Negotiated Settlement Agreement", <u>but</u> "does not have any objection to the remainder of the proposed Negotiated Settlement Agreement."
>
> (March 29, 2006 letter, page 1)
>
> (b) "it is BCOAPO's position that the question of the proper allocation of the revenue shortfall arising from Methanex leaving the PNG-West system should properly be addressed by a Commission panel."
>
> (supra, page 2)
>
> (c) "BCOAPO is prepared to cooperate in expediting the resolution of this issue. It does not believe that an oral hearing is necessary; certainly a full 2006 Revenue Requirement proceeding is not necessary."
>
> (supra, page 2)
>
> (d) "BCOAPO submits that this issue can appropriately be resolved in a written hearing process, provided that parties are given an opportunity to address an additional round of information requests to PNG-West to ensure that all necessary and appropriate evidence is before the Commission."
>
> (supra, page 2)
>
> (e) "BCOAPO agrees that the record in this proceeding is essentially complete. It would not propose to adduce further evidence. However, it is requesting a limited round of information requests, simply for the purpose of ensuring that relevant information, which is not included in the formal record but which was referred to in the course of settlement negotiations by PNG is a part of the record."
>
> (April 4, 2006 letter, page 2)"

At paragraph 9 of its June 6, 2006 Reply, PNG comments as follows:

> "It is disingenuous for BCOAPO to have asked the Commission to make a decision with respect to Item 1 pursuant to this written proceeding after telling the Commission it has no objection to the remainder of the Settlement Agreement, and to then turn around and say it is not in a position to make "meaningful submissions" to the Commission with respect to Item 1, that the Commission now needs to embark on some further process to determine this issue and that after

> the Commission makes a decision the settlement process should "reconvene" taking into account the Commission's decision…".

In PNG's submission, no further information is needed for the Commission to make a decision on Item 1 and BCOAPO's relative risks theory to apportion the revenue deficiency has no merit (PNG's June 6, 2006 Reply, paragraphs 10-14).

In the "Conclusion" of its June 6, 2006 Reply, PNG requests a timely decision by the Commission without additional process noting that six months have passed since PNG filed its Application and it has credit facilities that are maturing on July 24, 2006.

In its Reasons for Decision and Order No. G-66-06, the Commission Panel found that BCOAPO's submissions made it clear that there was no agreement before the Commission Panel to approve. The Commission Panel stated that it was not prepared to impose a settlement on the parties in this proceeding, which would be the effective result if it accepted the PNG submissions on the proposed settlement.

The Commission Panel also determined that it was not in a position to decide the Application, including Item 1 of the proposed Settlement Agreement, without further process. In an effort to establish an effective and efficient process, the Commission Panel requested submissions from all Parties related to appropriate steps and timing for either an oral and/or written hearing process, the issues to be considered, confirmation of the issues that may have been resolved during the NSP, and the nature of any proposed evidence to be filed and a justification for such evidence.

On the basis of BCOAPO's May 29 and June 2, 2006 submissions, it appeared that Item 1 and now Item 17, "Return on Equity and Capital Structure" of the proposed Settlement Agreement are the aspects of the Application which, in BCOAPO's view, remain in dispute. In an effort to limit the issues and any additional evidence to be adduced in this proceeding, the Commission Panel sought to confirm whether any or all other aspects of the Application continue to be accepted by the NSP participants as set forth in the document styled "Negotiated Settlement Agreement" and dated March 15, 2006.

The Commission Panel noted that there had been ample opportunity for all parties to develop an evidentiary record and that it did not consider it appropriate at that late stage to embark upon a further and more extensive examination of the issues that should have been properly developed by that time. The Panel, therefore, indicated that it would require a detailed explanation of the nature of any further evidence proposed and a justification for such evidence. By Order No. G-66-06, the Commission Panel requested that BCOAPO and any other Registered Intervenors provide comments on the nature and extent of the further process by Friday, June 16, 2006 and that PNG provide reply comments by Monday, June 19, 2006.

6.0 SUBMISSIONS IN RESPONSE TO COMMISSION ORDER NO. G-66-06

BCOAPO, Mr. Childs and PNG filed submissions in response to Order No. G-66-06 and the Commission Panel's request.

In BCOAPO's view, there were two separate but related issues related to Item 1 of the proposed settlement agreement:

1. the proper regulatory treatment of the revenue requirement shortfall from the loss of Methanex; and
2. the appropriate application of the Commission's decision with respect to (1).

BCOAPO considered that the issue of the proper regulatory treatment of the revenue shortfall arising from the loss of Methanex is a legal question requiring a Commission decision with respect to the statutory requirements of the Act as judicially interpreted and considered in the light of PNG's present situation. BCOAPO did not believe that it could usefully add anything further to the submissions already before the Commission on this issue. BCOAPO stated that "once the commission's decision has been issued, the remaining issues could be easily resolved …".

BCOAPO advocated an oral hearing to address the two separate but related issues arising with respect to Item 1. BCOAPO stated that it would be prepared to call evidence on the appropriate allocation of the Methanex revenue shortfall at such a hearing and would be prepared to respond to information requests, if the Commission so required, and that it should be open to PNG to file such further evidence as it considered appropriate on this issue. BCOAPO attempted to justify its request to file this evidence by stating that "what is presently before the Commission does not appropriately address this issue".

With respect to any issues that may have been resolved during the NSP, BCOAPO's position was that "final resolution of any of these issues is dependent on the Commission's decision with respect to the appropriate regulatory treatment of the Methanex revenue shortfall".

Mr. Childs submitted that a written hearing process would be more appropriate and expedient and that it should include an initial round of written negotiating positions by PNG and participating intervenors followed by a second and final round of revised negotiating positions, as appropriate. He also proposed a number of issues to be considered in this process.

PNG also proposed a written process based on the evidentiary record established to date. PNG submitted that there is an extensive evidentiary record before the Commission on which the Commission can make a decision with respect to the Application.

In the Reasons for Decision attached to Order No. G-77-06, the Commission Panel noted that there have been three rounds of information requests to date and opportunities for submissions. The Commission Panel further noted and that BCOAPO had not previously requested that it be allowed to file evidence when given the opportunity to do so when the Commission Panel sought submissions to establish a process to consider Item 1 of the proposed settlement document. The Commission Panel also observed that while BCOAPO had requested the opportunity to file further evidence, it had not explained or provided any substantive justification for the introduction of new evidence to the extent required by Order No. G-66-06.

Having received no submissions in response to its request in Order No. G-66-06 that could assist the Commission Panel to understand the nature and extent of evidence that BCOAPO considered would be helpful in the decision-making process, the Commission Panel concluded that no further evidence was necessary and that the further process to consider the Application would be a written process consisting of Argument by PNG, Intervenor Argument and PNG Reply Argument.

In the Reasons accompanying Order No. G-77-06, the Commission Panel rejected PNG's alternate proposal which would have allowed PNG to simply confirm that its applied-for cost of service for rate making purposes was that set out in the regulatory schedules attached to the proposed settlement document. The Commission Panel's purpose in so doing was to avoid the possibility of improperly narrowing the scope of argument. The Commission Panel also again refused to adopt the approach advocated by BCOAPO that would result in an advance ruling on the issue of the proper regulatory treatment of the revenue requirement shortfall from the loss of Methanex (Order No. G-77-06, Appendix A, p. 5 of 6).

By Order No. G-77-06, the Commission closed the evidentiary record and established a timetable for the filing of Argument with PNG's Argument required by July 7, 2006, Intervenor Argument by July 17, 2006 and PNG Reply Argument by July 24, 2006.

7.0 ARGUMENT FILED IN RESPONSE TO ORDER NO. G-77-06

7.1 PNG ARGUMENT

PNG filed its Argument on July 7, 2006 and requested approval of its 2006 revenue deficiency as set out in the proposed settlement document of $4.091 million, rather than the revised revenue deficiency of $4.435 million contained in the updated Application (Exhibit B-13). PNG's Argument addressed its 2006 Revenue Requirements by topics of Cost of Service, Rate Base, Deferral Accounts, Gas Deliveries and Margin Forecasts, Customer Rates and Just and Reasonable Rates. PNG's Argument also included summary regulatory schedules for the Cost of Service Comparison, Utility Income and Return, Utility Rate Base, Income Taxes, Common Equity and Return on Capital.

7.1.1 Cost of Service

<u>Operating, Maintenance, General and Administrative Expenses</u>

Operating, Maintenance, General and Administrative Expenses, excluding the company use gas costs, have increased to $13.997 million in 2006 from $13.539 million under the NSP 2005 settlement ("NSP 2005"). Operating expenses (net of transfers to capital and company use gas costs) are $212,000 higher than 2006 primarily due to the salary adjustment provisions of a three-year collective agreement that was effective November 1, 2004. Maintenance expenses are expected to be $39,000 higher in 2006, which PNG described as being consistent with actual costs from 2001 to 2005. Administrative and general expenses in 2006 are budgeted to be about $207,000 higher than 2005 mainly due to increased labour and employee benefits costs offset by a reduction in PNG's share of the Commission's administrative costs.

<u>Other Cost of Service Items</u>

A net decrease of $159,000 has occurred in 2006 from NSP 2005 related to transfers to capital, property taxes, depreciation, amortization and other income. PNG notes that a significant increase in property taxes has been offset by lower depreciation expense, higher transfers to capital and a substantial increase in the shared service cost recoveries from Pacific Northern Gas (N.E.) Ltd. ("PNG (N.E.)").

Income Tax Expense and Return on Rate Base

The revenue requirement for income taxes, return on common equity, short-term and long-term debt interest and preferred share dividends has decreased by $1,252,000 to $14.620 million in Test Year 2006 from $15.872 million in NSP 2005. The decrease is due to lower income tax rates, lower depreciation expense and lower return on common equity.

The return on common equity of $4,959 million for 2006 compared to $5,857 for NSP 2005 is due to increases in the allowed rate of return on common equity offset by decreases in rate base (PNG Argument, p. 18). PNG is requesting a risk premium of 65 basis points above the low risk benchmark utility and a deemed common equity component of 40 percent. For years PNG's allowed risk premium was 75 basis points which was reduced to 65 basis points in the PNG 2004 Revenue Requirement Decision. PNG submits that a 65 basis point relative risk premium is the minimum acceptable level having regard to PNG's risk profile. PNG anticipated it would be able to access the debt market in mid-2006 and achieve and maintain an equity component of 40 percent but with it being later in the year and its actual equity component being above 40 percent, the actual return on equity will be lower than forecast.

7.1.2 Rate Base

PNG's forecast mid-year 2006 rate base has decreased to $131.2 million from $133.5 million in NSP 2005. PNG performed a review of its transmission system to determine which facilities are required to provide safe, reliable and efficient service to its remaining customers following the closure of the Methanex plant. PNG determined that it could deactivate compressor stations R2 and R4, a 10 inch loop (52.8 miles in length), a 6 inch lateral to Kitimat (32.97 miles in length) and a Methanex meter and regulating station. These assets have in-service dates of 1968-69 and 1981-82 with an original cost of $15.581 million and a depreciated value on December 31, 2005 of $5.05 million.

PNG is seeking Commission approval to transfer the net book value of $5.05 million of these assets from plant in-service to a non-rate base interest bearing deferral account effective January 1, 2006. PNG is also requesting that the account be amortized on a monthly basis over 10 years commencing January 2006. PNG is also seeking approval that a notional account be set up as described in Exhibit B-1, Tab Application, page 7 to record the risk-weighted foregone return and if the plant is returned to service then the unamortized deferral account balance and the risk-weighted foregone return will be added back to plant in-service.

7.1.3 Deferral Accounts

Information on PNG's deferral accounts is found in Exhibit B-10, Tab 2, pages 10 to 12 with a subsequent correction made to reduce the amortization expense from $928,000 to $901,000. The amortization expense for the deactivated facilities is forecast to be $668,000 in 2006. A depreciation adjustment credit deferral amortization of $658,000 for over-depreciated assets is described in Exhibit B-10, Tab 2, page 11 with background information provided in Exhibit B-10, pages 2 to 3.

By letter dated October 4, 2005 PNG applied to the Commission for approval to record the contract termination payment of approximately $23.3 million in an interest bearing deferral account to the benefit of customers. The amount to be amortized each year is to be proposed in the annual revenue requirements application and is subject to approval by the Commission. This treatment was accepted in the 2005 NSP.

PNG is proposing to amortize the termination payment over the 44-month period from March 2006 to October 2009 to coincide with the original expiry date of the Methanex contract. PNG is seeking Commission approval to amortize $5.553 million of the contract termination payment in 2006 rates.

PNG is also seeking Commission approval to amortize the customers' $169,855 after tax share of the income trust application hearing costs at 20 percent per year commencing in 2006.

7.1.4 Gas Deliveries and Margin Forecasts

PNG forecasts deliveries to its customers for 2006 that are lower than the volumes used in the 2005 NSP. The 2006 volumes are about 25.7 TJ lower than 2005 NSP with 25.4 TJ of the volume decrease due to the Methanex closure. The total decrease in margin of approximately $10.8 million in 2006 compared to NSP 2005 is primarily due to the decrease in the Methanex margin of about $10.4 million. The remainder of the volume and margin decrease is mainly due to declines in use per account. The use per account of residential customers has decreased to 82.4 GJ in 2006 compared to 84 GJ in NSP 2005. The small commercial use per account is forecast to decrease to 361.3 GJ in 2006 from 366.3 GJ in NSP 2005. PNG attributes the decline in residential/small commercial use per account to high gas commodity costs and the current economic conditions in PNG's service area. The deliveries to small industrial customers are forecast to be slightly higher in 2006 by 14,000 GJ compared to NSP 2005. However, due to changes in the composition of the class, the 2006 margin is expected to decrease by $47,600 from NSP 2005. The Methanex contract terminated at the end of February 2006 and PNG recorded the Methanex margin for January and February 2006 under the small commercial class. The small commercial class is forecast to have a decrease in deliveries of 14,000 GJ in 2006 compared to NSP 2005 but a decline in margin of $78,000. The 2006 deliveries to West Fraser are expected to decrease by 175,000 GJ in 2006 compared to NSP 2005 but the margin is expected to increase by $42,000. Deliveries to Alcan for 2006 are expected to be at historical levels, which results in a decrease in volumes of 32,000 GJ for 2006 and a decrease in margin of $52,000 compared to NSP 2005.

7.1.5 Customer Rates

PNG is seeking Commission approval to adjust its 2005 customer rates to recover the 2006 revenue deficiency of $4.091 million. PNG is also seeking Commission approval of a 2006 RSAM (Revenue Stabilization Adjustment Mechanism) rate rider of $0.301/GJ to replace the interim rate rider of $0.26/GJ effective January 1, 2006. PNG is also seeking approval of its company use gas forecast and estimated cost, which would result in a permanent Company Use Gas Cost Rate of $0.185/GJ effective January 1, 2006 in place of the $0.305/GJ interim rate.

PNG provided a rate comparison table for residential Rate Schedule ("RS") 1 class and the small commercial class RS 2 class that shows the components of delivery charges and gas commodity charges for December 31, 2005 and the applied-for rates for January 1, 2006, April 1, 2006 and July 1, 2006. Based on the 2006 forecast use per account of 82.4 GJ for residential and 361.3 GJ for small commercial, PNG calculates the annual bill using the applied-for delivery charge and gas commodity rates. The following table reproduces the PNG rate comparison table for the total delivery charge, commodity cost and annual bill.

	($/GJ)			
Customer Class	Dec. 31/05	Jan. 1/06	Apr. 1/06	Jul. 1/06
Residential (RS 1)				
Delivery Charge	$7.355	$8.602	$8.602	$8.602
Commodity Charge	$9.608	$9.895	$8.245	$7.475
Total Gas Rate	$16.963	$18.497	$16.847	$16.077
Annual Bill using 82.4 GJ	$1,398	$1,524	$1,388	$1,325
Small Commercial (RS 2)				
Delivery Charge	$6.280	$7.337	$7.337	$7.337
Commodity Charge	$9.651	$9.873	$8.223	$7.458
Total Gas Rate	$15.931	$17.210	$15.560	$14.795
Annual Bill using 361.3 GJ	$5,756	$6,218	$5,622	$5,345

PNG estimates that the termination of the Methanex contract will result in about a $100 per year increase in delivery charges for residential customers.

PNG is also seeking Commission approval of revised rate structures for its RS 4, RS 5 and RS 6 customer classes as shown in Exhibit B-1, Tab Application, pages 48 to 52 with the following modifications that were discussed during the NSP process in March 2006:

a) A monthly fixed charge of $125 is to apply to the RS 4 customer class instead of no monthly fixed charge as originally proposed by PNG.

b) The tariff for the RS 6 seasonal off-peak customer class would extend the off-peak period to include November and March subject to PNG adding a provision to its tariff providing PNG with the right to curtail service in November and March to meet the gas requirements of its year round firm customers.

7.1.6 Just and Reasonable Rates

PNG's submissions regarding the Commission's obligation to fix rates that permit PNG the opportunity to recover all of its cost of providing service (including the fair rate of return on common equity approved for PNG by the Commission are based on subsections 60(1) and 59(5) of the Act and are set out in PNG's submissions dated April 28, May 9, May 29 and June 6, 2006 concerning Item 1 (Methanex Termination Payment) of the proposed Settlement Agreement. PNG adopts and relies on those submissions for the purposes of its final argument.

PNG argues that the revenue shortfall arising from the termination of the Methanex contract does not represent any specific costs of providing service but simply is the extent to which PNG's overall cost of providing service exceeds forecast margin recovery now that Methanex has terminated its contract. PNG submits that disallowing recovery of any portion of the revenue deficiency would be an arbitrary disallowance of PNG's forecast 2006 costs without evidentiary or legal basis for such a disallowance.

PNG submits that it has taken all reasonable and prudent steps to reduce its costs. It points to the major internal reorganization which included closing down of over-the-counter service offices and restructuring its head office when Methanex shut down for one year starting on July 1, 2000. PNG also submits that it has reduced its 2006 costs by:

- deactivating facilities in response to the Methanex closure and earning a short-term interest rate return on the unamortized balance of those facilities rather than a rate base rate of return. The deactivation is expected to reduce property taxes by $300,000 per year starting in 2007.

- using a 40 percent deemed equity component rather than its significantly higher actual common equity component.

- seeking and obtaining approval to reduce its share of Commission costs in 2006 from $323,000 to $70,303.
- by removing employee bonuses from pensionable earnings in calculating pension benefit costs resulting in a reduction of $74,000 in the applied-for 2006 company benefits.
- a unilateral lump sum credit of $200,000 applied to 2006 cost of service.

In PNG's submission, the Application, as summarized in the schedules attached to its Argument, based on the information responses and submissions filed subsequent to the conclusion of the NSP settlement discussions, fully support a Commission finding that the 2006 rates applied for by PNG are just and reasonable.

7.2 BCOAPO ARGUMENT

BCOAPO filed its Argument on July 17, 2006 and states that the key issue in this proceeding is whether the Act, particularly section 59, as interpreted by the Courts, requires the Commission to allocate all of the revenue requirement shortfall arising from the closure of the Methanex Kitimat plant to ratepayers. BCOAPO states that it is PNG's position that it does, while BCOAPO's submission is that it does not. BCOAPO refers to its submissions on this legal issue in its May 4, 2006 Reply Argument. BCOAPO comments that if it was possible to reach agreement on this issue that was acceptable to the Commission then other issues would likely have been resolved along the lines suggested in the proposed Settlement Agreement.

BCOAPO states that its concern is not solely with the impact on ratepayers in 2006 but the continuing impact to allocate all of the Methanex revenue requirement shortfall to ratepayers and the increased impact when the deferred Methanex termination payments end in 2009. BCOAPO submits that this issue has to be addressed now particularly in light of the impact of the Supreme Court Decision in ***ATCO***. In BCOAPO's view, the Commission must decide on the basis of legal arguments before it whether the responsibility for the Methanex revenue requirements shortfall should be for: a) PNG's ratepayers; b) PNG shareholders; or c) some combination of the two. BCOAPO acknowledges that this third option involves some determination by the Commission of the appropriate allocation. In the absence of specific evidence on this issue, BCOAPO submits that a 50/50 split would not be inappropriate. BCOAPO states that once that decision is made, given Commission Order No. G-77-06 and for the purpose of establishing PNG's 2006 revenue requirements, all aspects of the proposed Settlement Agreement other than Item 1 can consider to be accepted by BCOAPO.

With regards to Item 17 of the proposed Settlement Agreement, BCOAPO accepts that PNG's return on equity for 2006 has been established by the Commission. BCOAPO refers to its previous submissions and states that it takes the position that the level of return on equity, particularly with respect to the risk premium has to be taken into account in determining the proper allocation of the Methanex revenue requirement shortfall.

7.3 CHILDS ARGUMENT

Mr. Childs filed his Argument on July 17, 2006 which discusses rate affordability and suggests that the Commission Decision on the Application:

i) Start with a 50/50 apportionment between PNG's shareholders and customers of the Methanex shortfall on net margin of $4.8 million as outlined in Item 1 of the proposed Settlement Agreement.

ii) Alternatively, use a 50/50 apportionment of the net revenue deficiency of $4.091 million as outlined in the proposed Settlement Agreement. Mr. Childs considered this alternative to be more realistic, more fair and would take into account PNG's $709,000 of cost reductions.

7.4 PNG REPLY ARGUMENT

PNG filed its Reply Argument on July 24, 2006. PNG submits that apart from the issue of recovery of the revenue deficiency arising from the termination of the Methanex contract, neither BCOAPO nor Mr. Childs have taken any issue with PNG's applied-for 2006 revenue requirements. PNG notes that both BCOAPO and Mr. Childs persist in the assertion that the revenue shortfall arising from the termination of the Methanex contract can somehow be divorced from the cost of providing service. In PNG's view, a disallowance of any of the revenue shortfall would simply be a disallowance of an equal amount of PNG's costs.

PNG states that the proposed 50/50 split of the Methanex revenue shortfall between customers and the shareholders advocated by BCOAPO and Mr. Childs is arbitrary, has no evidentiary basis and would have a significant adverse effect on PNG and its customers. As an example, PNG states that it is very unlikely that it would be able to comply with its financial covenants under its operating/risk management lines of credit.

PNG submits that the BCOAPO makes a contradictory argument when it acknowledges that PNG's return on equity for 2006 has been established by the Commission but then should be effectively reduced in 2006 because the revenue shortfall arising from the termination of the Methanex contract is a risk for which the shareholders had previously been compensated. PNG argues that this assertion by BCOAPO has no merit for the reasons outlined in paragraphs 8 to 14 and paragraphs 12 to 14 of PNG's May 9, 2006 and June 6, 2006 reply submissions, respectively. PNG states that BCOAPO provided no substantive response to PNG's submissions on this matter despite multiple opportunities to do so and that PNG's marginally higher risk premium merely acknowledges that PNG's industrial load exposes PNG to a greater risk of being uncompetitive compared to other utilities. It says the risk premium never compensated nor did the Commission intend to compensate PNG's shareholders for the regulatory risk that the Commission would unilaterally set rates at levels insufficient to recover PNG's cost of service.

PNG notes that Mr. Childs accepts PNG's 2006 return on equity but continues to submit that PNG's rates should be set on some notion of customer "affordability" rather than in reference to PNG's cost of service. PNG states that "affordability" is not a test under the Act or the relevant case law. PNG argues that to the contrary, in exchange for the obligation to provide safe and reliable service, the Act requires that rates be fixed to provide the utility with the opportunity to recover its reasonably incurred costs, which are necessary to provide that service. PNG notes that there is no evidence in this case that PNG's applied-for rates are unaffordable and the applied-for April 1, 2006 rates are lower than the rates that were approved and in effect on December 31, 2005.

In conclusion, PNG submits that there is a statutory obligation upon the Commission to fix rates that permit PNG the opportunity to recover all of its costs of service including the fair rate of return on equity already approved by the Commission. PNG states that the leading case authority is ***Hemlock Valley*** which is substantially based on ***B.C. Electric***. PNG submits that rates which are insufficient to provide a utility the opportunity to recover its costs of providing service including the fair rate of return on equity are unjust and unreasonable under the Act. PNG states that it will be impossible to recover its costs of providing service, if as BCOAPO and Mr. Childs advocate, PNG is not allowed to recover the revenue shortfall resulting from the termination of the Methanex contract in its customer rates.

8.0 COMMISSION DETERMINATION

After a considerable amount of process and submissions subsequent to having established a negotiated settlement process to consider PNG's 2006 Revenue Requirements Application ("2006 RRA"), the Commission Panel is in a position to render a decision on PNG's Application and the issues related thereto, particularly those raised by BCOAPO and Mr. Childs in their various submissions.

Following a review of the submissions allowed by Order No. G-40-06 related to Issue 1 (Methanex Termination Payment) of the proposed settlement document dated March 15, 2006, the Commission Panel by Letter No. L-19-06 dated May 17, 2006,endeavoured to seek further submissions on issues raised by parties This included further submissions related to the application of ***Hemlock Valley***, the relevance of "affordability" and the authority of the Commission to reduce rates, the principles or methodology and evidence that the Commission could use to determine an appropriate allocation of the revenue deficiency as requested by intervenors, and the precedential aspect of this Decision in respect of future revenue shortfalls related to the loss of Methanex.

In view of the responses received to Letter No. L-19-06, further process, and ultimately a different process, was required to consider PNG's 2006 RRA.

The Reasons that follow will focus on two predominant issues raised by parties which, based on the proposed settlement document, have been termed: "Item 1 - Allocation of Revenue Deficiency"; and "Item 17 - Return on Equity and Capital Structure". Consideration of these items will be followed by the Commission Panel's determinations related to various elements of PNG's 2006 RRA as outlined in PNG's July 7, 2006 Argument which, the Commission Panel notes, do not appear to be in dispute.

I. Item 1: Allocation of the Revenue Deficiency

BCOAPO reiterates in its July 17, 2006 Argument that the key issue in this proceeding is the "legal question" of whether the Commission is required to allocate to ratepayers all of the revenue requirement deficiency arising from the closure of the Methanex plant.

The arguments related to this issue are most fully discussed in BCOAPO's May 4, 2006 Reply Argument and PNG's May 9, 2006 Reply Submission which are summarized in section 4.0 of these Reasons for Decision.

Relevant Statutory Provisions and Case Law

These arguments raise the question of the proper interpretation, in the light of relevant judicial decisions, of sections 59 and 60 of the *Act*¸ specifically 59(5) and 60(1)(b) which establish the requirement that the Commission set just and reasonable rates. Pursuant to subsection 59(5), a rate is "unjust or unreasonable" if the rate is:

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust or unreasonable for any other reason.

Paragraph 59(4)(a) states that it is a question of fact, of which the commission is the sole judge, whether a rate is unjust and unreasonable, and section 60 provides that:

60(1) In setting a rate under this Act or the regulations

(a) the commission must consider all matters that it considers proper and relevant affecting the rate,

(b) the commission must have due regard to the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59.

PNG submits that allocating any of the remaining deficiency to PNG's shareholders would contravene paragraph 59(5)(b) of the Act, whereas BCAOPO submits that the question of how section 59 of the Act should be applied in PNG's unique and current situation is a matter that requires Commission determination.

The Commission Panel agrees with both BCOAPO and PNG that the decisions of ***Hemlock Valley*** and ***B.C. Electric***, both of which have considered sections 59 and 60 or similar predecessor provisions of the Act, are applicable to the regulation of utilities in British Columbia.

The Commission Panel, however, does not consider that the ***ATCO*** decision, which dealt with the question of whether the Alberta Energy and Utilities Board had the authority to allocate to ratepayers a portion of the gain on the sale of a utility asset, is particularly germane. Although the Supreme Court of Canada in that case commented that "the rate-setting process is a speculative procedure in which both the ratepayers and the shareholders jointly carry their share of risk related to the business of the utility (see MacAvoy and Sidak, at pp. 239-39)", the issue before the Court (as well as that considered in the text referenced at para. 37, p. 9 of BCOAPO's May 4 filing) related to the risk associated with utility assets. The Commission Panel does not consider that the ***ATCO*** decision goes so far as to "set a balance between shareholders and ratepayers in the allocation of the revenue requirement shortfall that the utility faces", as suggested by BCOAPO (May 4, 2006 filing, para. 39, p. 10).

In ***B.C. Electric***, which was considered and applied in ***Hemlock Valley***, Mr. Justice Martland of the Supreme Court of Canada discussed (at p. 856) what are now paragraphs 59(5)(a) and (b) and commented that:

> "Clearly, as between these two matters there is no priority directed by the Act, but there is a duty imposed upon the Commission to have due regard to both of them. The rate to be imposed shall be neither excessive for this service nor insufficient to provide a fair return on the rate base. <u>There must be a balancing of interests.</u> In my view, however, if a public utility is providing an adequate and efficient service (as it is required to do by s. 5 of the Act), without incurring unnecessary, unreasonable or excessive costs in so doing, I cannot see how a schedule of rates, which, overall, yields less revenue than would be required to provide that rate of return on its rate base which the Commission has determined to be fair and reasonable, can be considered, overall, as being excessive. …". (emphasis added)

The issue of the appropriate balancing of the interests of the utility on one hand and its customers on the other, was also addressed by the Court in ***Hemlock Valley*** (at p. 21) when it stated that:

> "the proper balancing of interests which the Commission carried out was done and completed when it settled the rate base, fixed the rate of return and determined the costs of operation allowable for rate-making purposes."

In ***Hemlock Valley***, the Commission had attempted to balance the interests of the utility and its customers when it allowed a rate increase for the utility, but directed that it be phased in over three years to avoid or lessen "rate shock". The Court overturned the Commission decision's to phase in the rate increase (which did not compensate the utility for deferring recovery of its cost of capital), reasoning that to do so would preclude the utility from earning the rate of return found by the Commission to be the fair and reasonable return on equity.

BCOAPO, however, suggests that ***Hemlock Valley*** was not intended to apply to a utility in PNG's unique situation and essentially submits that the allocation of the revenue shortfall to ratepayers would in this instance be unjust and unreasonable. BCOAPO suggests that ***Hemlock Valley*** and ***B.C. Electric*** apply to a "normal" utility, but they do not apply where ratepayers are being asked to cover a revenue requirement shortfall arising from a risk for which shareholders had previously been compensated, nor where there was substantial risk of a utility losing customers as a result of the proposed increase in rates (BCOAPO May 4, 2006 filing, paras. 29/30, p. 7).

Commission Panel Analysis and Findings

The Commission Panel acknowledges that ***Hemlock Valley*** did not deal with a situation involving the loss of a significant customer. Nor arguably does it apply until the point where the Commission has made a finding or determination on a utility's cost of service. The Commission Panel notes that, relying upon ***B.C. Electric*** and the utility counsel's submissions, the Court in ***HemlockValley*** commented (p. 21) that:

> "The Utilities Commission Act empowers the Commission to determine what is a fair and reasonable rate of return upon the appraised value of the property of regulated utilities, but, <u>having done so</u>, requires the Commission to set rates so as to allow recovery of a rate which permits an opportunity to earn that return." (emphasis added)

In this context, therefore, the Commission Panel considers ***Hemlock Valley*** to be most useful in terms of reaffirming the principles discussed in ***B.C. Electric***.

In any event, the Commission Panel considers that it is in this instance bound by the requirements upon the Commission established by the Act and by the manner in which PNG is and has been regulated.

The Commission Panel agrees with BCOAPO that PNG is unique, particularly in view of its heavy reliance on a small number of industrial customers, and also agrees with PNG that the utility has higher business and financial risks than a low-risk benchmark utility.

However, although PNG is unique, it is and has been regulated by the Commission under the Act on a traditional cost of service basis. What this means is that this utility, which is a virtual monopoly provider of natural gas in its service area, is permitted under the Act to recover the reasonable and prudent costs of providing its services in exchange for the obligation to provide safe and reliable service. One of the regulator's tasks, therefore, is to balance the need for the Utility to recover its reasonable and prudent costs with the need to ensure that ratepayers are charged fair and reasonable rates. Rates charged to customers are based on costs incurred by the utility to provide service. If the Commission finds certain costs to be imprudent or unreasonable, it will disallow such expenditures and reduce proposed rates accordingly.

The statutory obligation to approve rates which will afford a fair compensation for the services rendered and provide the utility with a fair and reasonable return was articulated by Mr. Justice Locke in ***B.C. Electric***, (at pp. 846 and 848):

> "In my opinion the true meaning of the relevant sections of the *Public Utilities Act* is that a utility is given a statutory right to the approval of rates which will afford to it fair compensation of the services rendered and that the quantum of that compensation is to be the fair and reasonable rate of return upon the appraised value of the property of the company referred to in s. 16(1)(b) [ss. 59(5)(a) and (b) and 60(1)(b)(i). …
>
> The obligation to approve rates which will provide the fair return to which the utility has been found entitled is, in my opinion, absolute, which does not mean that the obligation of the Commission to have due regard to the protection of the public, as required by s. 16(1)(b) [ss. 59(5)(a) and (b) and 60(1)(b)(i)], is not to be discharged. It is not a question of considering priorities between "the matters and things referred to in Clauses (a) and (b) of subsection (1) of s. 16 [now ss. 59(5)(a) and (b)]. The Commission is directed by s. 16(1)(a) [now s. 60(1)(a)] to consider all matters which it deems proper as affecting the rate but that consideration is to be given in the light of the fact that the obligation to approve rates which will give a fair and reasonable return is absolute." [emphasis added]

The Commission Panel considers, therefore, that it is required, by virtue of sections 59 and 60 of the Act to allow the utility to recover its reasonable and prudent cost of service, to be determined on the basis of its 2006 RRA and the evidence adduced in this proceeding.

As noted by PNG, the revenue deficiency arising from the termination of the Methanex contract does not represent any specific costs of providing service. It is simply the extent to which PNG's overall costs of providing service exceeds forecast margin recovery from PNG's customers now that Methanex has terminated its contract. A revenue deficiency (or surplus) simply dictates whether an increase (or decrease) in rates is required. The Commission Panel, therefore, does not consider the revenue deficiency, in the context of cost of service regulation, to be a separate line item that, in and of itself, is capable of adjustment or reduction.

The Commission Panel, therefore, finds that to allocate any of the net revenue deficiency resulting from the termination of the Methanex contract to PNG's shareholders, as advocated by BCOAPO and Mr. Childs, would result in rates that do not permit PNG to recover its costs of providing service and would, therefore, contravene sections 59 and 60 of the Act. The Commission Panel agrees with PNG that the allocations proposed by BCOAPO and Mr. Childs would simply be an arbitrary disallowance of PNG's forecast costs, without any evidentiary or legal basis having been established for such a disallowance.

Given the statutory obligations imposed upon the Commission, there is simply no principled basis before the Commission Panel in this proceeding to allow it to appropriately deviate from the statutory requirement to allow the utility to recover its prudent and reasonable cost of providing service, and certainly there is no evidence to support an allocation or to select a specific allocation of the revenue deficiency, other than to the utility's customers.

The Commission Panel finds that PNG's proposed method of allocating a revenue deficiency resulting from the loss of the Methanex contract to be appropriate.

More specifically, the Commission Panel also accepts PNG's proposal, discussed at pages 44 and 45 of the Application (Exhibit B-1), to allocate the revenue deficiency based on customer class gross margin and to treat small industrial sales and transportation service customers as one customer class when allocating the revenue deficiency.

Other arguments raised by BCOAPO and Mr. Childs and concerns expressed by many other intervenors and interested persons relate to affordability of rates and PNG cost control.

The Commission Panel notes BCOAPO's comment that for some time now PNG's residential rates have been either barely competitive or uncompetitive with electricity rates and PNG's response that the rate impact to other customers is "modest and manageable" when comparing the rates payable effective April 1, 2006 with the rates that were in effect December 31, 2005. The Commission Panel agrees with BCOAPO that PNG's comparison is not particularly supportive of PNG's position given the fluctuations in commodity prices during this period.

The Commission Panel, however, agrees with PNG that "affordability" is not a test under the Act or the relevant case law and that it is a vague, relative and potentially shifting concept. The Commission Panel notes the comments of Mr. Justice Rothstein of the Federal Court of Appeal in ***TransCanada Pipelines Ltd. v. Canada (National Energy Board)***, [2004] F.C.A. 149 (at para. 43):

> "While I agree with the appellant that the impact on customers or consumers cannot be a factor in the determination of the cost of equity capital, any resulting increase or decrease in tolls may be a relevant factor for the Board to consider in determining the way in which a utility should recover its costs. It may be that an increase is so significant that it would lead to "rate shock" if implemented all at once and therefore should be phased in over time. It is quite proper for the Board to take such considerations into account, provided that there is, over a reasonable period of time, no economic loss to the utility in the process. In other words, the phased in tolls would have to compensate the utility for deferring recovery of its cost of capital. <u>In the end, where a cost of service method is used, the utility must recover its costs over a reasonable period of time, regardless of any impact those costs may have on customers or consumers"</u> (see *Hemlock Valley Electrical Services Ltd. v. British Columbia Utilities Commission et al*., [1992] 12 B.C.A.C. 1 at 20-21 (C.A.)) [emphasis added].

Furthermore, the Commission Panel finds that there is no evidence before it in this proceeding which would allow it to determine that the rates proposed by PNG are not affordable or, conversely, to determine what a more appropriate "affordable" rate would be and how that could be achieved.

It is evident though that increases in the delivered cost of gas do impact PNG's residential and commercial customers (PNG May 9, 2006 filing, para. 24, p. 7) and the Commission Panel accepts PNG's submissions and assurance that the Utility has responded by taking all reasonable and prudent steps to reduce its costs as a result of the loss of margin from its industrial customers. PNG states that "customer impacts" are always considered when the cost of service is established in the sense that customers have an interest in ensuring that the utility's costs are reasonable and not overstated and that such impacts are reflected in the cost of service that was considered during the NSP and was reflected in the proposed settlement document and now PNG's July 7, 2006 Final Argument.

The Commission Panel notes the actions and efforts which PNG has taken to reduce its costs in the past when it faced a reduction in revenue from industrial customers and the steps taken to reduce its 2006 costs as outlined in its Application and at page 9 of its April 28, 2006 filing. The Commission Panel also notes PNG's assertion that there are no material maintenance capital expenditures which could be eliminated without endangering PNG's obligation to provide safe and reliable service to its customers. **The Commission Panel accepts that PNG has taken all prudent steps to manage and reduce its costs and that there are no unnecessary or unreasonable costs in the 2006 cost of service.**

It goes without saying that it is incumbent upon a regulated gas utility, and particularly so in this era of rising natural gas prices and the potential further loss of customers, to make best efforts to control and, where possible, reduce costs and the Commission Panel accepts that PNG has and will continue to do so.

The Commission Panel nevertheless remains concerned that PNG's rates are becoming less competitive and is mindful of the concerns expressed by a considerable number of interested parties earlier in this proceeding, including comments concerning the precarious state of the economy of the northwest and the difficulties faced by industrial commercial and residential customers alike (including Robin Austin, MLA, April 6, 2006 Submission and Exhibits C11-3 and C11-4 (Petition); Terrace & District Chamber of Commerce, Exhibit C7-1; Mayor Talstra, City of Terrace, Exhibit C8-2; Kitimat Chamber of Commerce, Exhibit C13-1).

The Commission Panel notes that PNG conducts detailed monthly reviews of its financial and operating results. PNG suggests, therefore, that it would be in a position to determine whether lower customer rates would improve cost recovery and prevent PNG's recoverable margin from declining (PNG May 29, 2006 Response, Question 4, p. 7) and that PNG would, in such case, make an appropriate application to the Commission to reduce customer rates.

The Commission Panel therefore anticipates that PNG will continue to carefully monitor loss of load and decreases in volumes and margin and to be in a position to take steps as it considers appropriate and as discussed in its May 29, 2006 Response to Letter No. L-19-06, Question 4, and/or to report to the Commission on this subject in its next RRA.

II. Item 17: ROE and Capital Structure

PNG requests that the Commission set PNG's return on common equity using a 65 basis points risk premium above the low risk benchmark utility and a deemed common equity ratio of 40 percent. PNG's allowed ROE is derived from the Commission's Automatic Adjustment Mechanism which is used to calculate the ROE for a low-risk benchmark utility and a utility-specific risk premium for each utility. The Commission's March 2, 2006 Decision related to the application by Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. to determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism revised the 2006 ROE for a low-risk benchmark utility to 8.80 percent. On March 9, PNG subsequently revised its Application to include a ROE of 9.45 percent to reflect the revision in the ROE for a low-risk benchmark utility (Exhibit B-13).

The Commission Panel notes that PNG's risk premium was reduced by 10 basis points to 65 basis points in the Commission Decision dated July 29, 2004 regarding PNG's 2004 RRA.

The Commission Panel in this proceeding has heard no persuasive evidence that PNG's risk premium should be further reduced and certainly no evidence or submissions to suggest a specific appropriate reduction. **Therefore the Commission Panel approves an ROE for PNG for 2006 of 9.45 percent based on a 40 percent equity component.**

PNG's proposal to issue $25 million of long-term debt and to lend $8 million to PNG (N.E.) is approved for 2006 ratemaking purposes. PNG's requested long-term effective debt rate of 6.74 percent is approved for 2006 ratemaking purposes. PNG's proposed 6 percent short-term debt rate on the positive short-term

debt component of the capital structure for 2006 is approved. PNG is to record the difference between the 6 percent debt rate and the actual short-term interest and expenses in the short-term interest rate deferral account.

In its response to Letter No. L-19-06, BCOAPO stated that "the evidentiary record in this proceeding is not sufficient to allow the Commission to make an appropriate apportionment of the revenue deficiency between the remaining ratepayers and PNG's shareholders. BCOAPO submitted that evidence with respect to the appropriate return on equity risk premium for PNG post-Methanex and on the methodology for determining an appropriate allocation of the revenue deficiency is now required. However, in its 2-page response dated June 16, 2006 to Commission Order No. G-66-06, BCOAPO did not, as had been requested, provide a detailed explanation of the nature and extent of any further evidence proposed and a justification for such evidence to assist the Commission Panel to understand what was required and how it would be helpful in the decision-making process.

Although the Commission Panel closed the evidentiary record for this proceeding, this does not preclude the appropriate ROE for PNG from being subject to further review. BCOAPO, Mr. Childs or any other party is entitled to raise this issue, and any other related issues, and to present appropriate and relevant evidence for the Commission's consideration in the review associated with PNG's next RRA.

As well, BCOAPO had raised, in the context of Item 1, the following question: "Is what PNG is requesting a fair return on the rate base, taking into account its history and present circumstances?" (May 4, 2006, para. 33, p. 8) because in BCOAPO's view PNG has in the past obtained an approved ROE, which included a significant equity risk premium for which the potential loss related thereto has now largely occurred. In response, PNG took issue with what it termed BCOAPO's assertion that allocating the revenue shortfall to other customers would effectively amount to an over-recovery of costs by PNG.

The Commission Panel notes PNG's response that its higher risk premium, which is now 65 basis points above the equity risk premium for the low risk benchmark utility, represents approximately $340,000 of additional annual return to PNG's shareholders and that the net margin loss from the termination of the Methanex contract in 2006 would be approximately $4.8 million (PNG May 9, 2006 filing, para. 12, p. 4).

The Commission Panel does not consider that allocation of a revenue deficiency resulting from the Methanex contract at this time and in these circumstances will result in an over-recovery for PNG.

III. Other RR Items

Neither BCOAPO nor Mr. Childs has taken issue with any of PNG's other applied-for cost of service items as presented in the proposed settlement document or PNG's July 7, 2006 Final Argument.

1. Load Forecast *(Gas Deliveries and Margin Forecasts)*

The load forecasts appear reasonable and the Commission Panel accepts them as filed and updated by PNG.

2. Rate Redesign

PNG is proposing to redesign the rate structure for Commercial Interruptible (RS 4), Small Industrial Sales (RS 5), and Seasonal Off-Peak (RS 6) customers by eliminating a monthly charge based on minimum consumption volumes in favour of a basic monthly charge unrelated to volume for the RS 5 and RS 6 customers.

For RS 5 Small Industrial customers, PNG is proposing a monthly fixed charge of $410. For RS 6 Seasonal Off-Peak Customers it is proposing a monthly fixed charge of $125, to apply only in the off-peak months of March to November. A delivery charge equal to twice the large commercial firm sales delivery charge will apply to any deliveries to the RS 6 customers during the peak winter months of December to February.

PNG is proposing no basic monthly charge for interruptible customers (that is a basic monthly charge of zero), arguing (primarily) that fixed pipeline assets are built to serve firm customers. Moreover, there would be no minimum monthly charge for interruptible customers.

The impact of the proposed change will be quite beneficial to small volume customers (decreases of 1.2% for RS 4 customers and of 12% and 14% respectively for RS 5 and RS 6). The change will be detrimental but less noticeably so for medium and large volume customers in each class, increasing the bills by 0.1% to 2.4% depending on the class (Exhibit B-4, Response to BCUC IR 1 8.1 and Exhibit B-11, Response to BCUC IR 2 33.1 to 33.4).

The Commission notes that there were no submissions about this issue following the proposed Negotiated Settlement, which adopted monthly fixed charges as follows:

RS 4 Commercial Interruptible -	$125 per month
RS 5 Small Industrial Firm -	$410 per month
RS 6 Seasonal Off-Peak -	$125 per month during off-peak.

The Commission Panel accepts PNG's proposal to eliminate the monthly charge based on minimum consumption volumes in favour of a basic monthly charge effective January 1, 2006. The Commission Panel directs PNG to include a monthly charge of $125 for the RS 4 Commercial Interruptible customers effective January 1, 2006.

<u>Extend Seasonal Off-Peak Period to include November and March</u>

PNG is also proposing to extend the seasonal off-peak period to include November and March (Exhibit B-1, p. 52). PNG confirmed that if the system peak day occurred in the months of November or March it would be able to meet its firm load. PNG also confirmed that, if the change is approved, the revised tariff will contain a condition allowing them to curtail seasonal customers in November and March if necessary to meet firm customer demand (Exhibit B-11, Responses to BCUC IR 2 35.2 to 35.4).

The Commission Panel finds the change proposed by PNG to be reasonable and to be one which poses no threat to the supply reliability for firm customers. **The Commission Panel accepts PNG's proposal to extend the seasonal off-peak period, subject to PNG's commitment to include a tariff provision allowing curtailment of seasonal off-peak customers in November and March effective January 1, 2006.**

3. Rate Base

The Commission Panel approves the deactivation of compressor stations R2 and R4, a 10 inch loop (52.8 miles in length), a 6 inch lateral to Kitimat (32.97 miles in length) and a Methanex meter and regulating station.

The Commission Panel approves PNG's request to transfer the net book value of $5.05 million of the facilities which it will deactivate from plant in service to a non-rate base interest bearing deferral account and to amortize that account on a monthly basis over 10 years commencing January, 2006. The Commission approves the accounting treatment of the deactivated facilities as proposed by PNG (Exhibit B-1, Tab Application, pp. 6-7). PNG's foregone return proposal is not accepted at this time, however, PNG may apply for Commission approval to record the foregone return should the deactivated facilities be reactivated and the merits of that application will be considered at that time.

The Commission Panel approves PNG's 2006 forecast capital additions as set out in the February 17, 2006 Update (Exhibit B-10). PNG is to file a report with the Commission by 2006 year-end detailing the activities taken in respect of the Arden Valley Rehabilitation project and all associated costs incurred with this project.

4. Deferral Accounts

Subject to the adjustments required in these Reasons for Decision, the Commission Panel approves the applied-for Deferral Accounts.

5. Recapitalization Application Hearing Costs

The Commission Panel notes that in the July 29, 2004 Decision related to PNG's 2004 RRA, the Commission was of the view that the costs associated with the regulatory review of the associated January 30, 2004 Recapitalization Application should be shared between the ratepayers and the shareholders and allowed PNG to recover Commission and Intervenor Recapitalization Application costs billed to the Utility by the Commission. However, in its Decision dated September 9, 2005, the Commission noted, at p. 48, that one of the approvals sought by PNG, in paragraph 1 of its subsequent Recapitalization Application dated December 17, 2004, was subject to the condition "that no costs associated with this [recapitalization application] and no transactions costs, including amalgamation and securities issuance and redemption costs, related to the foregoing transactions shall be recovered through customer rates" ("PNG's proposed condition"). In this proceeding, PNG was asked to confirm that PNG's 2006 revenue requirements and the proposed rates do not contain any costs related to the Recapitalization Application and, if not, to explain why not (BCUC IR No. 1.25.3, p. 53). In response, PNG indicated that it had "recorded all of the 2005 income trust application hearing costs in the BCUC proceedings deferral account pending obtaining all of the approvals required for the conversion to proceed" and that "PNG's share of the 2005 [recapitalization application] hearing costs will remain in that account until all of the approvals are obtained to enable PNG to commence the conversion process".

The Commission Panel notes that during the course of this proceeding PNG indicated that it was evaluating the efficiency of raising capital under an income trust structure for a proposed "KSL Project" and confirmed that it could give no assurances that the recapitalization under an income trust ownership structure will occur (PNG April 24, 2005 filing, Q. 4.2 and 4.3, pp. 5-6).

In the circumstances, the Commission Panel does not consider that it is bound, beyond the July 29, 2004 Decision related to PNG's 2004 RRA, to allow PNG to recover or share these costs between the ratepayers and shareholders as set out in that Decision. Rather, based on PNG's subsequent proposed condition as noted and as approved in the September 9, 2005 Decision and, given the status of the approved recapitalization under an income trust structure and the circumstances related thereto, the Commission Panel considers that the costs associated with the subsequent Recapitalization Application should perhaps more properly be to the sole account of the shareholders as reflected in PNG's proposed condition. **The Commission Panel denies PNG's request to amortize the customers' $169,855 after tax share of the second Recapitalization Application hearing costs at 20 percent per year commencing in 2006. For greater certainty, this amount may remain in the deferral account, subject to review of the appropriate recovery of these costs in the next RRA.**

6. Cost of Service

The Commission Panel finds that PNG's 2006 operating, maintenance, general and administrative expenses, and other cost of service items to be prudent and reasonable and appropriate to ensure the safe and efficient operation of its system. The Commission Panel approves for 2006 PNG's requested transfer to capital rate of 19.3 percent.

The Commission Panel approves the cost pools subject to allocation by PNG to PNG (N.E.) as set out in the Application. The Commission Panel accepts that PNG's allocation of Account 728 costs to PNG (N.E.) is appropriate and that relative rate base is the appropriate allocator.

PNG's request to revise the interim company use gas cost rate of $0.305/GJ to a permanent rate of $0.185/GJ is approved, effective January 1, 2006.

7. Customer Rates

The Commission Panel approves PNG's 2006 revenue requirement as set out in PNG's July 7, 2006 Argument, pages 18-23, subject to the required adjustment for amortization of Recapitalization Application hearing costs. PNG's proposal to amortize the Methanex termination payment of $23.3 million over the 44-month period from

March 2006 to October 2009 is approved which results in a credit of approximately $5.6 million from the Methanex contract termination payment to the 2006 cost of service. PNG's request to make the permanent RSAM rate rider $0.301/GJ effective January 1, 2006 (Exhibit B-10, p. 7) is approved.

IV. Conclusion

PNG is to file regulatory schedules and an amended summary of Rates and Bill Comparison Schedules based on PNG's Application, as revised, and the adjustments contained in these Reasons.

The Commission will accept, subject to timely filing, amended Gas Tariff Rate Schedules in accordance with these Reasons.

PNG is to comply with all directions contained in these Reasons.

TransCanada Pipelines Limited, 2004 Mainline Tolls and Tariff Application
NEB Decision RH-2-2004 PHASE II

National Energy Board

Office national de l'énergie

Reasons for Decision

TransCanada PipeLines Limited

RH-2-2004

Phase II

April 2005

Cost of Capital

Canada

National Energy Board

Reasons for Decision

In the Matter of

TransCanada PipeLines Limited

2004 Mainline Tolls and Tariff Application

RH-2-2004

Phase II

April 2005

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Abbreviations

10^9m^3	Billion cubic metres
$10^6m^3/d$	Million cubic metres per day
2004 Tolls Application	TransCanada's 2004 Mainline Tolls and Tariff Application
8.25% JSDs	TransCanada's 8.25% US $460 million junior subordinated debentures due 2047
8.50% Debentures	TransCanada's 8.50% US $200 million debentures due 2023
8.75% JSDs	TransCanada's 8.75% US $160 million junior subordinated debentures due 2045 that were redeemed in 2003
Act	*National Energy Board Act*
Alliance	Alliance Pipeline Ltd.
ANR	ANR Pipeline Company
ATWACC	After-Tax Weighted-Average Cost of Capital
Bcf/d	Billion cubic feet per day
BC System	TransCanada BC System (formerly Alberta Natural Gas Company Ltd)
Board	National Energy Board
CAPM	Capital Asset Pricing Model
CAPP	Canadian Association of Petroleum Producers
Coral	Coral Energy Canada Inc.
DBRS	Dominion Bond Rating Service
DCF	Discounted Cash Flow
EBIT	Earnings before interest and taxes
ECAPM	Empirical Capital Asset Pricing Model
Enbridge	Enbridge Pipelines Inc.
ERP	Equity Risk Premium
FERC	Federal Energy Regulatory Commission (US)

FFO	Funds from operations
Foothills	Foothills Pipe Lines Ltd.
GAAP	Generally Accepted Accounting Principles
GJ	Gigajoule
GLGT	Great Lakes Gas Transmission Company
GTN	Gas Transmission Northwest Corporation
IGUA	Industrial Gas Users Association
Iroquois	Iroquois Gas Transmission System
JSDs	Junior subordinated debentures
LDCs	Local distribution companies
LNG	Liquefied natural gas
M&NP	Maritimes & Northeast Pipeline
Mainline	TransCanada Mainline natural gas transmission system
MMcf/d	Million cubic feet per day
Moody's	Moody’s Investors Service
MRP	Market Risk Premium
NEB	National Energy Board
NGTL	Nova Gas Transmission Limited
Northern Border	Northern Border Pipeline Company
Northwest Pipeline	Northwest Pipeline Corporation
Ontario	Minister of Energy for the Province of Ontario
Phase I	Phase I of RH-2-2004
Phase II	Phase II of RH-2-2004
PNGTS	Portland Natural Gas Transmission System
Review Application	TransCanada’s application for review and variance of the RH-4-2001 Decision and related Orders (resulting in the RH-R-1-2002 Decision)
ROE	Rate of return on common equity

S&P	Standard and Poor's
Tcf	Trillion cubic feet
Tennessee	Tennessee Gas Pipeline Company
TJ	Terajoule
TQM	Trans Québec & Maritimes Pipeline Inc.
TransCanada	TransCanada PipeLines Limited
TTF	Mainline's Tolls Task Force
US	United States of America
Union	Union Gas Limited
Vector	Vector Pipeline (U.S.)
Viking	Viking Gas Transmission Company
WACC	Weighted-Average Cost of Capital
WCSB	Western Canada Sedimentary Basin
Westcoast	Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission Canada

Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* and the regulations made thereunder; and

IN THE MATTER OF an application filed by TransCanada PipeLines Limited pursuant to Part IV of the Act, for orders fixing and approving tolls that TransCanada shall charge for transportation services provided on its Mainline natural gas transmission system between 1 January 2004 and 31 December 2004; and

IN THE MATTER OF Hearing Order RH-2-2004, as amended, setting down Phase II of the Proceeding;

Heard in Calgary, Alberta on 29 and 30 November 2004; 1, 6, 7, 8, 13, 14, 15, 16 and 17 December 2004; 17, 18, 19, 20, 21, 25, 26 and 27 January 2005; and 1, 2 and 4 February 2005;

BEFORE:

G. Caron	Presiding Member
J.S. Bulger	Member
D.W. Emes	Member

Appearances	Participants	Witnesses
C.K. Yates, Q.C. W.M. Moreland	TransCanada PipeLines Limited	S.M. Brett P.R. Carpenter A.M. Engen D.K. Ferguson C.R. Frew R.K. Girling A. Jamal A.L. Kolbe G.S. Lackenbauer W.A. Langford P.J. Murphy M.J. Vilbert G.J.W. Zwick
N.J. Schultz	Canadian Association of Petroleum Producers	L.D. Booth B.E. Frank D.H. Gilbert H.W. Johnson R.R. Moore P.M.G. Nettleton

Appearances	Participants	Witnesses
	Canadian Association of Petroleum Producers (continued)	M. Pinney S.D. Reilly A. Safir G.L. Stringham P.G. Tahmazian
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B. Troicuk	BP Canada Energy Company	
M. Stauft	Coral Energy Canada Inc.	
S. Young	Nexen Marketing	
J.C. Turchin E. Sweet	Minister of Energy for the Province of Ontario	
R. Richard	Procureur général du Québec	
M.A. Fowke R.M. Zanin	National Energy Board	

Glossary of Terms

Basis point	One-hundredth of a percentage point, used in reference to interest rates or rates of return on equity
Beta	A measure of the systematic risk of a security, which estimates the extent to which a stock's price fluctuates more or less than average when the market fluctuates
Billing determinants	Calculated values used in allocating a revenue requirement between tollpayers. Billing determinants account for both volumes and distance
Bond rating	A quality rating assigned by credit rating agencies as an indication of creditworthiness
Book value	The amount at which an item appears in the books of account and financial statements
Business risk	The risk attributed to the nature of a particular business activity (as distinct from financial risk). For pipelines, it typically includes supply, market, regulatory, competitive, and operating risks
Capital Asset Pricing Model (CAPM)	A method used to estimate the cost of equity capital by comparing the return and risk characteristics of an individual company's shares with the market average
Capital attraction standard	The aspect of the fair return standard that requires that the return of a regulated utility permit incremental capital to be attracted to the enterprise on reasonable terms and conditions
Capital structure	The way in which a business is financed; generally expressed as a percentage breakdown of the types of capital employed
Comparable earnings test	A comparison of the returns earned by companies with similar investment risk to that of the regulated utility's operations
Comparable investment standard	The aspect of the fair return standard that requires that the return of a regulated utility be comparable to the return available from the application of the invested capital to other enterprises of like risk
Competitive risk	The business risk that results from competition for customers at both the supply and market ends of a pipeline system

Cost of service	The total cost of providing service, including operating and maintenance expenses, depreciation, amortization, taxes, and return on rate base
Cross subsidization	The provision of financial support to a company's non-regulated operations by its regulated operations, or vice versa
Deemed capital structure	A notional capital structure used for rate-making purposes that may differ from a company's actual capital structure
Depreciation	A non-cash expense charged against earnings to write off the cost of an asset during its estimated useful life
Discounted Cash Flow (DCF)	A method used for estimating the cost of common equity based on the expected dividend yield of the company's shares and the expected future dividend growth rate
Economic resources	That portion of the technical resources that can be developed economically under anticipated economic conditions
Embedded cost of debt	The weighted-average historical cost of long-term debt outstanding
Equity Risk Premium (ERP)	A family of methods used for estimating the cost of common equity that includes the CAPM and ECAPM; it is based on the premise that an investment in common equity carries greater risk than an investment in either debt or preferred shares and, therefore, requires a higher return, or premium, over that required for bonds or preferred shares
Fair return standard	A standard that should be examined when setting the return allowed to a company; it is comprised of the comparable investment, financial integrity and capital attraction standards
FFO interest coverage	A financial ratio calculated as the funds from operations over gross interest incurred before subtracting capitalized interest and interest income
FFO to total debt ratio	A financial ratio calculated as the funds from operations over long term debt (including amount for operating lease debt equivalent) plus current maturities, commercial paper and other short-term borrowings
Financial integrity standard	The aspect of the fair return standard that requires that the return of a regulated utility enable the financial integrity of the regulated enterprise to be maintained

Financial risk	The risk inherent in a company's capital structure; financial risk increases as the proportion of debt increases in relation to shareholders' equity
Flow-through tax methodology	A method of estimating income taxes payable for a period based on taxable income as opposed to accounting income
Funds from operations (FFO)	The net income from a company's continuing operations plus depreciation, amortization, deferred income taxes, non-cash items, and interest expense
GH-6-96	NEB Proceeding on facilities application for the Sable Offshore Energy Project and the Maritimes & Northeast Pipeline Project (Reasons for Decision dated December 1997)
Group 1 companies	In 1985, for financial regulatory purposes, the Board divided the pipeline companies under its jurisdiction into two groups: Group 1 companies with extensive systems; and Group 2 companies with lesser operations
Interest coverage	The number of times that net income for a given year, before interest expense and income taxes, covers the annual interest expense
Investment risk	The total of a company's business risk and financial risk
K&V ATWACC Methodology	The specific ATWACC-based methodology used by Drs. Kolbe and Vilbert to estimate cost of capital
Market-to-book ratio	The ratio of the market price of a common share to its book value
Market risk	The business risk that stems from the overall size of the market and the market share that a pipeline is able to capture
Netback	The price that a producer of natural gas receives, based on the downstream market price less any charges for delivering the gas to market
Operating risk	The risk to the income-earning capability that arises from technical and operational factors
Pro forma	Describes a presentation of data, typically financial statements, where the data reflects the world on an 'as if' basis; for example, financial statements that are adjusted to reflect a projected transaction

Rate base	The amount of investment on which a return is authorized to be earned; it typically includes plant in service plus an allowance for working capital
Regulatory risk	The risk to the income-earning capability of the assets that arises due to the method of regulation of the company
Revenue requirement	The total cost of providing service, including operating and maintenance expenses, depreciation, amortization, taxes, and return on rate base
Return on rate base (return)	The return that a regulated company is authorized to earn on its approved rate base
RH-1-2001	NEB Proceeding on TransCanada's 2001-2002 Mainline Tolls and Tariff Application (Reasons for Decision dated November 2001)
RH-1-2002	NEB Proceeding on TransCanada's 2003 Mainline Tolls and Tariff Application (Reasons for Decision dated July 2003)
RH-1-70	NEB Proceeding for Mainline's tolls effective 1 January 1970 (Reasons for Decision dated December 1971)
RH-2-2004	NEB Proceedings on TransCanada's 2004 Mainline Tolls and Tariff Application (Phase I Reasons for Decision dated September 2004; Phase II Reasons for Decision dated April 2005)
RH-2-94	NEB Multi-Pipeline Cost of Capital Proceeding (Reasons for Decision dated March 1995)
RH-2-94 Formula	Formula used to determine the rate of return on common equity for certain NEB-regulated pipelines, established in the RH-2-94 Proceeding, as amended to eliminate rounding
RH-3-2004	NEB Proceeding on TransCanada's North Bay Junction Application (Reasons for Decision dated December 2004)
RH-4-2001	NEB Proceeding on TransCanada's 2001-2002 Mainline Fair Return Application concerning cost of capital for the Mainline (Reasons for Decision dated June 2002)
RH-R-1-2002	NEB Proceeding on TransCanada's Review Application of the RH-4-2001 Decision (Reasons for Decision dated February 2003)
Supply risk	The risk that the physical availability of natural gas could affect a pipeline's income-earning capability

Tariff	The terms and conditions under which the services of a pipeline are offered or provided, including the tolls, the rules and regulations, and the practices relating to specific services
Technical resources	Natural gas resources estimated by having regard for the geological prospects in an area or basin and anticipated technology. They are the sum of cumulative production (portions already produced), reserves (portions discovered, but not produced) and future resources (portions still undiscovered), with all given as marketable volumes. Marketable volumes for the future resources are determined by applying the recovery factors and surface losses applicable to pools discovered in the past
Test Year	A 12-month period used for rate-making purposes
Toll	The price charged by a pipeline company for the use of its facilities
Tolls Task Force	A joint industry task force initiated by TransCanada; its membership is comprised of a wide cross-section of the natural gas industry, including representatives of the producing, marketing, brokering and pipeline segments of the industry, provincial governments, LDCs, and industrial end-use customers
Ultimate potential	The sum of resources that have been discovered (including gas that has already been produced) and undiscovered resources that are expected to be discovered by future drilling
Utilization rate	A rate determined by dividing system throughput by pipeline design capacity, expressed as a percentage

Chapter 1

Introduction

1.1 Background

TransCanada PipeLines Limited (TransCanada) owns and operates the Mainline natural gas transmission system (Mainline), which is a high pressure natural gas transmission system that extends from the Alberta border across Saskatchewan, Manitoba, Ontario, through a portion of Quebec and connects to various downstream Canadian and international pipelines. In addition, the Mainline's integrated system includes contractual entitlements to transport natural gas on the Great Lakes Gas Transmission Company (GLGT) system from Emerson, Manitoba to St. Clair, Michigan; on the Union Gas Limited (Union) system from Dawn, Ontario to Parkway, Ontario and to Kirkwall, Ontario; and on the Trans Québec & Maritimes Pipeline Inc. (TQM) system from St-Lazare to St-Nicolas and East Hereford, all located in Quebec. Figure 1-1 shows a map of the Mainline's integrated system.

Prior to 1995, the Board generally approved pipeline tolls on an annual cost of service forward test year basis. During that period, the Mainline's cost of capital was typically examined every year as part of an annual cost of service tolls application.

In the fall of 1994, the Board held the Multi-Pipeline Cost of Capital Proceeding (RH-2-94). In the RH-2-94 Decision,[1] the Board approved a rate of return on common equity (ROE) for a benchmark pipeline, based primarily on the Equity Risk Premium (ERP) methodology. The ROE for the benchmark pipeline was set at 12.25 percent for the 1995 Test Year. The Board also adopted a formula for adjusting the ROE on an annual basis (RH-2-94 Formula).

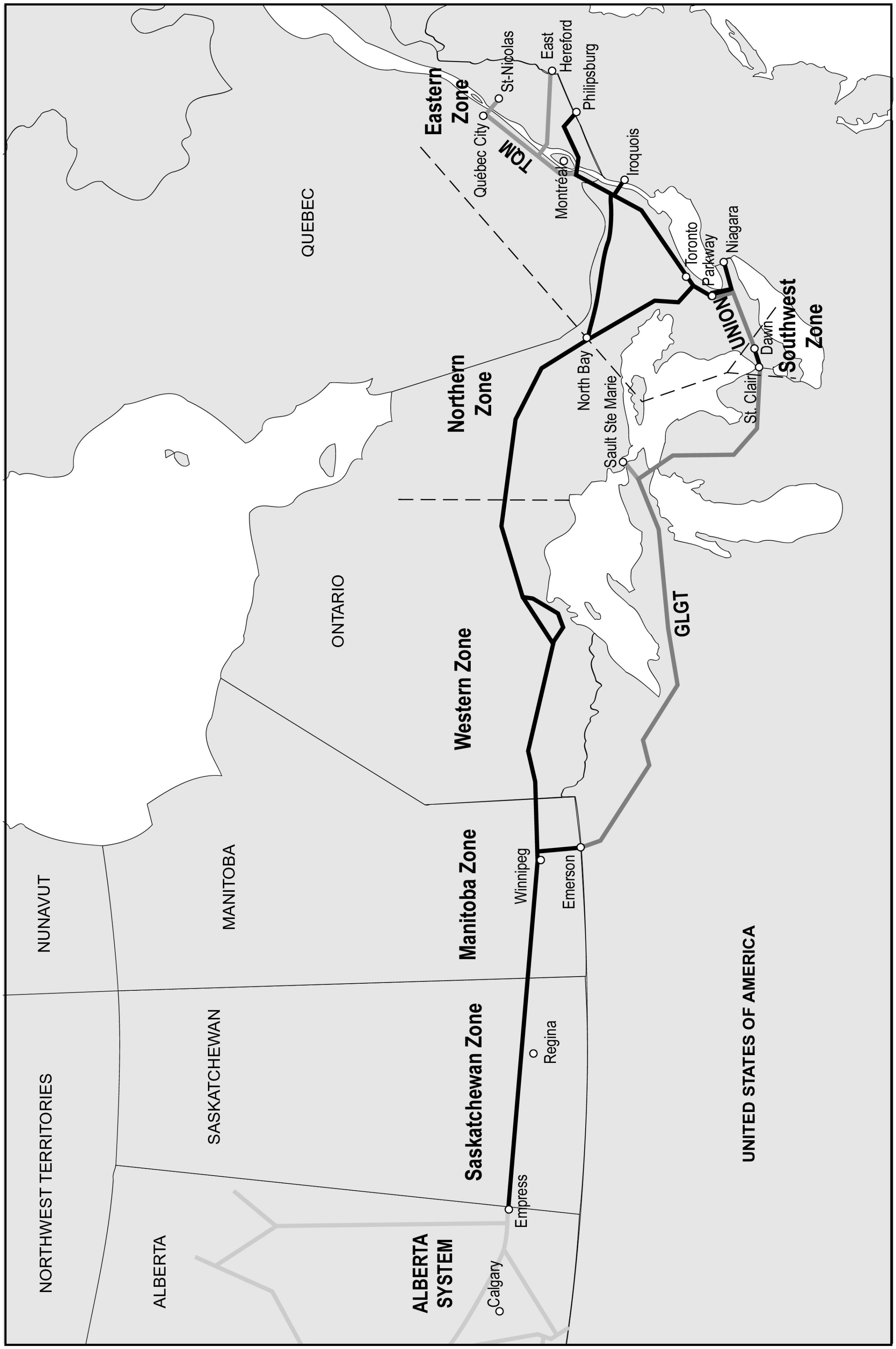
The ROEs resulting from the RH-2-94 Formula have been as follows: 11.25 percent in 1996; 10.67 percent in 1997; 10.21 percent in 1998; 9.58 percent in 1999; 9.90 percent in 2000; 9.61 percent in 2001; 9.53 percent in 2002; 9.79 percent in 2003; 9.56 percent in 2004; and 9.46 percent in 2005.

The RH-2-94 Decision stated that:

> The Board is of the view that the rate of return on common equity for the benchmark pipeline is appropriate for all of the pipelines subject to this proceeding. The Board is cognizant of the linkage between the rate of return on common equity and the pipelines' capital structures and has determined that any risk differentials between the pipelines can best be accounted for through

1 National Energy Board RH-2-94 Reasons for Decision, TransCanada PipeLines Ltd. et al. (Cost of Capital), March 1995 [hereinafter RH-2-94]

Figure 1-1
TransCanada Mainline



> adjustments to the common equity ratios rather than by making company-specific adjustments to the benchmark pipeline's rate of return on common equity.[2]

The Board decided that the overall business risk of TransCanada's Mainline, Foothills Pipe Lines Ltd. (Foothills), Alberta Natural Gas Company Ltd (now the TransCanada BC System) and TQM were such that a similar common equity ratio could be given to these four pipelines. The Board confirmed the Mainline's common equity ratio of 30 percent, which had been in place over the previous 15 years, except for 1982 and 1983 when a common equity ratio of 28 percent was deemed. The Board also indicated that given the then current cost rates, it was appropriate for TransCanada to maintain preferred shares in the Mainline's capital structure.

During the 1996-1999 period, the Mainline's tolls were approved by the Board based on the terms of the Incentive Cost Recovery and Revenue Sharing Settlement. That incentive agreement was a negotiated settlement between TransCanada and its stakeholders and incorporated a deemed common equity component of 30 percent and the ROEs resulting from the RH-2-94 Formula.

For the 2000 Test Year, the Board approved tolls for the Mainline, based on a one-year negotiated settlement, which incorporated the RH-2-94 Formula ROE on a deemed common equity component of 30 percent.

For 2001 and 2002, the Mainline's tolls reflected the terms of the two-year Mainline Service and Pricing Settlement. That settlement established a toll methodology and tariff provisions to be applicable for 2001 and 2002, and the components of the revenue requirement (other than cost of capital) to be used in the calculation of final tolls for 2001. The Board considered the 2001-2002 settlement in the RH-1-2001 Proceeding.[3]

In its 2001-2002 Fair Return Application, TransCanada sought review and variance of the RH-2-94 Decision. TransCanada proposed that the Board determine the Mainline's cost of capital for 2001 and 2002 utilizing an After-Tax Weighted-Average Cost of Capital (ATWACC) methodology. TransCanada sought approval of an ATWACC of 7.5 percent, adjusted in each of 2001 and 2002 for the difference between the market cost of debt and the embedded cost of debt of the Mainline. Alternatively, TransCanada requested that the Board establish an ROE of 12.50 percent on a deemed equity component of 40 percent. In the RH-4-2001 Decision,[4] the Board declined to adopt the ATWACC methodology and decided that the ROE resulting from the RH-2-94 Decision should continue to apply to the Mainline. The Board also concluded that the level of business risk facing the Mainline had increased since 1995 and approved an increase in the Mainline's deemed common equity ratio from 30 percent to 33 percent, effective 1 January 2001.

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2 RH-2-94, *supra*, note 1 at p. 6

3 National Energy Board RH-1-2001 Reasons for Decision, TransCanada PipeLines Ltd. (Tolls and Tariff), November 2001 [hereinafter RH-1-2001]

4 National Energy Board RH-4-2001 Reasons for Decision, TransCanada PipeLines Ltd. (Cost of Capital), June 2002 [hereinafter RH-4-2001]

On 16 September 2002, TransCanada applied for review and variance of the RH-4-2001 Decision and related Orders (Review Application). The Review Application was made on the grounds that the Board, in rendering the RH-4-2001 Decision, committed errors that raised doubts as to the correctness of the Decision. TransCanada submitted that the RH-4-2001 Decision resulted in prejudice or damage to the Mainline and its investor, TransCanada, by imposing an unfair return; prejudicing the ability of the Mainline to attract capital from TransCanada; placing the company at a competitive disadvantage; and prejudicing its ability to invest in the Canadian pipeline industry, including the Mainline and northern pipelines.

Also on 16 September 2002, TransCanada filed the Mainline's 2003 Tolls and Tariff Application, in which it requested that the 2003 return for the Mainline be determined by the Board in accordance with its disposition of the Review Application.

On 20 February 2003, the Board issued its RH-R-1-2002 Reasons for Decision,[5] in which it dismissed TransCanada's Review Application on the ground that the Review Application had not raised a doubt as to the correctness of the Board's RH-4-2001 Decision.

TransCanada sought leave to appeal the Board's RH-R-1-2002 Decision to the Federal Court of Appeal on 21 March 2003. Leave to appeal was sought on questions concerning the correctness of the legal test applied by the Board in establishing TransCanada's return and whether the Board fettered its discretion by basing the Mainline's ROE on the RH-2-94 Formula methodology. On 21 May 2003, the Federal Court of Appeal granted TransCanada's application for leave to appeal the Board's RH-R-1-2002 Decision.[6]

On 26 January 2004, TransCanada filed its 2004 Tolls and Tariff Application (2004 Tolls Application) with the Board, seeking approval of tolls on the Mainline for the period 1 January 2004 to 31 December 2004. Among other things, TransCanada sought approval of a fair return for 2004 that reflected an ROE of 11 percent on a deemed common equity ratio of 40 percent, which is equivalent to an ATWACC of 6.9 percent.

The Board issued Hearing Order RH-2-2004 on 23 March 2004, establishing a two-phase oral public hearing to consider TransCanada's 2004 Tolls Application. Phase I considered all issues raised by the 2004 Tolls Application, with the exception of cost of capital. Phase I was held in Ottawa, Ontario from 14 June 2004 to 25 June 2004. The RH-2-2004 Phase I Reasons for Decision were issued on 10 September 2004.[7]

With respect to cost of capital, the Board indicated in Hearing Order RH-2-2004 that it would be inappropriate to initiate further procedural steps in respect of Phase II until after the release of the Federal Court of Appeal Decision regarding TransCanada's appeal of the Board's RH-R-1-2002 Decision.

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5 National Energy Board RH-R-1-2002 Reasons for Decision, TransCanada PipeLines Ltd. (Review of RH-4-2001 Cost of Capital Decision), February 2003 [hereinafter RH-R-1-2002]

6 Federal Court of Appeal Docket No. 03-A-16, Order dated 23 May 2003

7 National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd. (Tolls and Tariff), September 2004 [hereinafter RH-2-2004 - Phase I Decision]

On 16 April 2004, the Federal Court of Appeal issued its reasons for judgment denying TransCanada's appeal.[8] On 20 April 2004, the Board sought comments from parties concerning the procedural implications of that Decision for Phase II of the RH-2-2004 Proceeding.

TransCanada advised the Board on 12 May 2004 that, in light of the Court of Appeal's Decision in *TransCanada v. NEB*, it would not seek variance from the RH-2-94 Formula for 2004. TransCanada also indicated that it maintained its 2004 Tolls Application concerning its applied-for capital structure, and it would therefore be seeking approval of the ROE stemming from the RH-2-94 Formula (9.56 percent for 2004) on 40 percent deemed equity. TransCanada filed related changes to its 2004 Tolls Application on 28 May 2004.

On 7 June 2004, the Board issued Order AO-1-RH-2-2004 setting out the procedure to be followed in Phase II, which was scheduled to commence on 25 October 2004 in Calgary, Alberta. As a result of TransCanada's decision not to seek variance from the RH-2-94 Formula for 2004, the Board removed "the appropriate rate of return on common equity (ROE) for the Mainline" from the Phase II List of Issues.

The issues that remained for the Board's consideration in Phase II were:

1. The appropriate capital structure for the Mainline;

2. The appropriate cost of debt for the Mainline, including any financial impact resulting from debt redemption; and

3. The appropriate effective date for any change to the Mainline's cost of capital.

The Canadian Association of Petroleum Producers (CAPP) filed a Notice of Motion on 4 June 2004, seeking a number of Board directions concerning the 28 May 2004 evidence of TransCanada.

After hearing from parties by way of written submission, the Board issued its ruling on CAPP's motion on 30 June 2004 (see Appendix I). The Board also issued Order AO-2-RH-2-2004, amending a number of dates in the Phase II Timetable of Events. The Board expressed the view that portions of TransCanada's evidence were not relevant to Phase II of the RH-2-2004 Proceeding, as the evidence suggested that the ROE for the Mainline in 2004 should be other than 9.56 percent. The Board directed that TransCanada file amendments to its evidence in such a way as to remove any direct or indirect inferences to an appropriate ROE other than 9.56 percent for the Mainline in 2004, by 15 July 2004.

On 13 July 2004, TransCanada sought an extension for the filing of its revised evidence, which was granted by the Board on 14 July 2004. TransCanada also requested that a number of other dates, including the start of the hearing, be amended. The Board issued Order AO-3-RH-2-2004 on 23 July 2004 and scheduled the Phase II Hearing to commence on 22 November 2004.

TransCanada filed its revised evidence on 29 July 2004. Unless otherwise noted, the information contained in these Reasons for Decision reflects TransCanada's revisions dated 29 July 2004.

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8 *TransCanada PipeLines Ltd. v. National Energy Board et al.,* [2004] F.C.A. 149 [hereinafter *TransCanada v. NEB*]

On 4 August 2004, the Board received a letter from CAPP in which it expressed the view that TransCanada had not complied with the Board's direction of 30 June 2004. The Board responded to CAPP on 12 August 2004 (see Appendix II) by reiterating its 30 June 2004 ruling that it would not allow TransCanada, through its ATWACC or other evidence, to do indirectly that which TransCanada has chosen not to do directly (that is, seek review of the RH-2-94 Formula). The Board also expressed the view that TransCanada should be allowed to present its case as it relates to the issues to be addressed in Phase II in the manner it deems appropriate, so long as the rules of natural justice are respected.

The Board issued Order AO-4-RH-2-2004 on 23 September 2004, by which it approved a revised timetable of events proposed by CAPP on 21 September 2004 and agreed upon by TransCanada and other active parties. The commencement of the Phase II Hearing was delayed one week to 29 November 2004.

The filing date for intervenor evidence was 19 October 2004. CAPP was the only intervenor to file evidence with the Board. The CAPP evidence was the subject of a motion filed by TransCanada on 12 November 2004. TransCanada requested that the Board clarify the issues to be considered in Phase II of RH-2-2004 and the parameters for the conduct and disposition of the proceeding. On 19 November 2004, the Board heard the TransCanada motion orally and issued its ruling from the Bench (see Appendix III). Among other things, the Board noted that TransCanada was seeking to have the Board consider return using a different methodology than the traditional methodology. The Board ruled that TransCanada was free to submit evidence and argue that an alternative approach should be utilized in making the determinations to be made in Phase II but that it would not, prior to hearing all of the evidence, make a determination on which approach or approaches should be used. Also, the Board agreed with TransCanada that its evidence need not be limited to examining changes since 2001 and accepted that the impact of tolls on customers is not a relevant consideration in the determination of cost of capital.

The hearing commenced on 29 November 2004 and adjourned on 17 December 2004. It reconvened on 17 January 2005 and was completed on 4 February 2005. The hearing lasted 22 days.

1.2 Overview of the Application

As noted above, the cost of capital aspects of the 2004 Tolls Application were considered in Phase II. For information on the other aspects of the 2004 Tolls Application, and the Board's Decisions on these matters, refer to the RH-2-2004 – Phase I Decision, which was issued on 10 September 2004.

With respect to cost of capital matters, TransCanada's applied-for 2004 revenue requirement included an overall rate of return on rate base of 8.93 percent, which incorporates the RH-2-94 Formula ROE of 9.56 percent for 2004 on a deemed common equity ratio of 40 percent (an increase from 33 percent to be effective 1 January 2004) and an average cost of debt of 8.73 percent.

The average applied-for cost of debt reflected TransCanada's proposed redemption of the US$ 200 million 8.50% Debentures (8.50% Debentures) and the US$ 460 million 8.25% Junior

Subordinated Debentures (8.25% JSDs) in July 2004. TransCanada submitted that junior subordinated debentures (JSDs) have comprised approximately ten percent of the Mainline's total capitalization in the form of preferred securities since 1998 and proposed to replace this ten percent preferred component of the Mainline's capitalization with seven percent unfunded debt and three percent common equity. Further information on the JSDs appears in Chapter 3; information on the cost of debt appears in Section 8.1.

Chapter 2

Legal Framework for Determining a Fair Return

In addition to the matters set out in the List of Issues for this proceeding, the methodology that the Board ought to employ in order to determine an appropriate capital structure for the Mainline was also the subject of considerable discussion in the hearing.

Position of TransCanada

TransCanada submitted that, as a matter of law, the Board is required to determine the cost of equity capital for the Mainline for 2004 using the comparable investment, capital attraction and financial integrity standards, which together comprise the fair return standard. TransCanada cited the *Northwestern Utilities Limited v. City of Edmonton,*[9] *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia et al.*[10] and *Federal Power Commission v. Hope Natural Gas*[11] cases as establishing this standard.

TransCanada argued that the fair return standard does not apply narrowly to either the rate of return on equity nor to the deemed equity component of a utility's capital structure; instead it applies to the total return on capital invested. Thus, in TransCanada's view, the Board's determination of a fair return on equity capital must involve consideration of evidence pertaining to the overall equity return. This is required by the fair return standard as articulated in *Northwestern Utilities (1929)*, and was endorsed by the Federal Court of Appeal decision in *TransCanada v. NEB*[12] and the Board in its RH-1-1970 Reasons for Decision[13].

While TransCanada's evidence pertaining to total return was primarily based on the ATWACC methodology (derived from the after-tax ROE and after-tax market cost of debt), TransCanada also discussed two other forms of total return: the total equity return (the dollar amount resulting from the product of the common equity ratio, the ROE and the rate base) and the rate of return on rate base (in this instance, calculated using after-tax ROE and before-tax embedded cost of debt).

TransCanada also expressed the view that the Board should approach its consideration of the evidence from a clean slate and not limit itself to the changes in business risk since it last assessed the Mainline's cost of capital (that is, in RH-4-2001, which pertained to the 2001 and 2002 Test Years).

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9 *Northwestern Utilities Limited v. City of Edmonton,* [1929] S.C.R. 186 [hereinafter *Northwestern Utilities (1929)*]

10 Bluefield *Waterworks & Improvement Co. v. Public Service Commission of West Virginia et al.* 262 U.S. 679 (1923) [hereinafter *Bluefield*]

11 Federal *Power Commission v. Hope Natural Gas* 320 U.S. 591 (1944) [hereinafter *Hope*]

12 *TransCanada v. NEB, supra* note 8

13 National Energy Board RH-1-70 Reasons for Decision, Trans-Canada Pipe Lines Limited (Tolls Application – Phase I), December 1971 [hereinafter RH-1-70]

Position of Intervenors

CAPP

CAPP argued that there were two distinct methodologies before the Board in this proceeding, the first being the Board's traditional framework and the other being the approach put forward by TransCanada, which focuses on a total return framework.

CAPP noted that the traditional framework was used by the Board in the RH-2-94 Reasons for Decision and was subsequently confirmed by the Board in RH-4-2001. CAPP favoured the Board's traditional approach, stating that such an approach involved a separate determination of a return on equity and of a capital structure. It argued that once the Board has followed its traditional approach, it simply produces an arithmetic result to arrive at the total return. CAPP expressed the view that there is no separate determination of a fair return and cited the Federal Court of Appeal in *TransCanada v. NEB* in support of this proposition.

The starting point under the traditional framework for establishing capital structure, in CAPP's submission, is an analysis of business risk, which typically looks at changes in business risk since the last time cost of capital was assessed. CAPP argued that the Board may also look at other factors such as the pipeline's financing requirements, the pipeline's size and its ability to access capital and that these factors are afforded some weight by the Board.

In CAPP's view, the RH-4-2001 Decision should serve as the baseline and the Board should assess what changes of significance, if any, have occurred since 2001. CAPP submitted that TransCanada should have to prove whether any such changes justify a change in capital structure. While the Board's findings should be limited to changes of significance since 2001, CAPP acknowledged that the Board could look at changes prior to 2001. However, CAPP reiterated the point that the most relevant evidence in this proceeding is that evidence which points to changes that have occurred since 2001.

CAPP argued that the capital structure could not be backed out of the total return and that the essence of TransCanada's total return comparisons approach is problematic because any actual comparative analysis involves businesses for which there is both return on equity information and capital structure information. CAPP argued that this approach is flawed because, to arrive at total return, one must make a finding on the return on equity, which is not an issue in this case, as TransCanada chose not to file an application for review of the ROE stemming from the RH-2-94 Formula.

Finally, CAPP submitted that what constitutes a fair return is a matter of opinion for the Board and not a matter of law or jurisdiction. In CAPP's view, the Board is entitled to bring its own judgment, experience and expertise to bear on the question of what constitutes a fair return.

IGUA

It was submitted by the Industrial Gas Users Association (IGUA) that this case was unusual because not all the elements of cost of capital were at issue. According to IGUA, the traditional methodology involves a separate determination of the return on equity and the equity ratio. The mathematical product of the return on equity and the equity ratio is then included as the equity return component of the revenue requirement and used to produce just and reasonable tolls.

IGUA referred to the RH-2-94 Decision, wherein the Board held that the capital structure set in that hearing would endure for an extended period of years, and more importantly, that the Board would consider a reassessment of capital structure on an individual basis, in the event of a significant change in business risk, in corporate structure or in corporate financial fundamentals. It argued that the re-examination mechanism established by the Board in 1994 has never been set aside in any subsequent decision and that it applies as a matter of principle today. IGUA contended that the traditional methodology that the Board applies calls for a party seeking a re-examination of capital structure to satisfy a significant change of circumstances test to obtain the relief that it seeks. IGUA further argued that this test exists and cannot be eliminated, without a motion to vary and set aside that feature of the RH-2-94 Decision, which has not been done in this case.

IGUA supported CAPP's suggestion that this case is simply an attempt to vary the Board's RH-4-2001 Decision and that TransCanada is trying to do indirectly what it could not do directly. IGUA submitted that in the RH-4-2001 Decision, the Board rejected the total return approach for determining the return component of just and reasonable tolls proposed by TransCanada, and also rejected that approach as a check for reasonableness on the traditional methodology.

Finally, IGUA argued that it is more appropriate for the Board to look at significant changes in business risk if the request for a change in capital structure occurs shortly after the last decision on the matter. A clean slate approach is only appropriate if the Board is dealing with a case that is occurring a substantial period of time after the ratios were initially established.

Coral

Coral Energy Canada Inc. (Coral) did not make submissions regarding which methodology the Board should employ in determining TransCanada's capital structure. Coral acknowledged that as a practical matter, it acceded to TransCanada's position that the Board should employ the clean-slate methodology but noted that this should not be taken as a concession that Coral had to do so or as disagreement with the submissions for CAPP or IGUA on that point.

Ontario

The Minister of Energy for the Province of Ontario (Ontario) raised a number of legal principles for the Board to consider in relation to TransCanada's application. Among them, Ontario submitted that the Act contains no provision that requires the Board to determine a utility's rate of return on capital; the Act requires only that all tolls be just and reasonable. Ontario cited the Federal Court of Appeal in *TransCanada v. NEB* in support of its submission that the Board's authority to determine just and reasonable tolls is not limited by any statutory direction; instead it is guided by its own judgment. Ontario also stated that customers and consumers have an interest in ensuring that the Mainline's costs are not overstated.

It was noted by Ontario that the Board has adopted a cost of service methodology, although it was open to the Board to choose one of many approaches. Ontario argued that, having chosen this approach, the Board must faithfully determine the Mainline's costs. In cost of capital proceedings, the Board is entitled to estimate the cost of capital, including the deemed equity level of the Mainline and the Mainline's overall return on capital, on the basis of the evidence before it and its own judgment.

Views of the Board

As discussed in Chapter 1, the Mainline's 2004 ROE has already been established through the application of the RH-2-94 Formula and is not at issue in this proceeding. Determining the appropriate capital structure for the Mainline is the central issue within this proceeding; however, the central legal issue is whether the Board is legally compelled to employ a specific methodology in arriving at its determination of an appropriate capital structure for the Mainline. The submissions of parties concerning the Board's legal obligations in establishing the Mainline's capital structure raised points relating to four factors: the Act's requirement for just and reasonable tolls; cost of service regulation; the fair return standard; and the methodology to be used to determine capital structure.

Just and Reasonable Tolls

Any consideration of tolls must commence with an examination of the Board's mandate as set out in section 62 of the Act:

> All tolls shall be just and reasonable, and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate.

The methodology that the Board must employ in setting just and reasonable tolls is not prescribed by law, nor is there any statutory obligation requiring the Board to specifically consider and establish a rate of return for the companies it regulates. The Federal Court of Appeal in *TransCanada v. NEB* held that while the Board has, for the Mainline, traditionally applied a cost of service methodology from which just and reasonable tolls are derived, the Board may adopt a different methodology for determining tolls.[14] This finding affirms a similar principle found in two previous decisions of that same Court.[15]

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14 *TransCanada v. NEB, supra* note 8 at paras. 29 and 30

15 The Court specifically affirmed its previous decision in *B.C. Hydro* (*infra* note 18) and, by doing so, also affirmed the same finding it made in *Trans Mountain* (*infra* note 16)

In *Trans Mountain Pipe Line Company v. National Energy Board et al.,*[16] the Federal Court of Appeal found that the method to be used and the factors to be considered in determining tolls:

> must be left to the discretion of the Board which possesses in that field an expertise that judges do not normally have. If, as it has clearly done in this case, the Board addresses its mind to the right question, namely, the justness and reasonableness of the tolls, and does not base its decision on clearly irrelevant considerations, it does not commit an error of law merely because it assesses the justness and reasonableness of the tolls in a manner different from that which the Court would have adopted.[17]

The broad authority of the Board was also set out in *B.C. Hydro and Power Authority v. Westcoast Transmission Company Ltd. et al*.[18] In that case, the Court noted that the regulatory system established by Part IV of the *National Energy Board Act* differs from the situation in *Northwestern Utilities (1929)* where there were specific statutory directions to the Public Utilities Board contained in the *Gas Utilities Act*. Thurlow C.J. in *B.C. Hydro* went on to state:

> There are no like provisions in Part IV of the National Energy Board Act. Under it, tolls are to be just and reasonable and may be charged only as specified in a tariff that has been filed with the Board and is in effect. The Board is given authority in the broadest of terms to make orders with respect to all matters relating to them. Plainly, the Board has authority to make orders designed to ensure that the tolls to be charged by a pipeline company will be just and reasonable. But its power in that respect is not trammelled or fettered by statutory rules or directions as to how that function is to be carried out or how the purpose is to be achieved. In particular, there are no statutory directions that, in considering whether tolls that a pipeline company proposes to charge are just and reasonable, the Board must adopt any particular accounting approach or device or that it must do so by determining cost of service and a rate base and fixing a fair return thereon.[19]

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16 *Trans Mountain Pipe Line Company v. National Energy Board et al.,* [1979] 2 F.C. 118 [hereinafter Trans Mountain]

17 *Ibid*. at para. 9

18 *B.C. Hydro and Power Authority v. Westcoast Transmission Company Ltd. et al.,* [1981] 2 F.C. 646 (C.A.) [hereinafter *B.C. Hydro*]

19 *Ibid*. at pp. 655-656

Cost of Service Regulation

It has been the Board's practice since its first rate hearing, RH-1-70, to utilize a forward test year cost of service approach to set tolls for the Mainline. This approach involves estimating the costs to be incurred by the Mainline over a future period, known as a test year. In order to recover its approved costs, the Board permits TransCanada to charge the Mainline's customers tolls. These tolls should provide TransCanada with sufficient revenue to recover the Mainline's prudently incurred costs, including its cost of capital, while at the same time "fairly allocating charges to users in relation to the costs and benefits of different services."[20]

The Federal Court of Appeal in *TransCanada v. NEB* noted that once the Board adopted the cost of service methodology "it had to faithfully determine the Mainline's costs based upon the evidence and its own sound judgment."[21] As the Court also pointed out, the largest component of the Mainline's costs is its cost of capital, which is included in the Mainline's cost of service.[22]

Rothstein J.A. in *TransCanada v. NEB* described the cost of capital to a utility this way:

> The cost of capital to a utility is equivalent to the aggregate return on investment investors require in order to keep their capital invested in the utility and to invest new capital in the utility. That return will be made in the form of interest on debt and dividends and capital appreciation on equity. Usually, that return is expressed as the rate of return investors require on their debt or equity investments.[23]

Under the Board's traditional approach, once the Board has established a rate of return on equity and debt, the two numbers are consolidated into a composite rate of return on capital, based upon the relative amounts of debt and equity in the capital structure. The Board constructs for each pipeline a capital structure, which reflects the amount of debt and equity the pipeline needs to finance its prudently incurred costs. This assessment is made with the assistance of expert evidence. In order to account for the greater or lesser risk attributed to an individual pipeline, the equity component of the capital structure is adjusted. The higher the risk attributed to a pipeline, the greater the required equity component of its capital structure. This is so, because equity serves as support for debt,

20 *TransCanada v. NEB, supra* note 8 at para. 5

21 *Ibid*. at para. 32

22 *Ibid*. at para. 5

23 *Ibid*. at para. 6

whose repayment is most often fixed. A higher level of equity provides comfort to debt lenders by improving the likelihood that their investment will be recovered in the event the corporation cannot meet its financial obligations.

Fair Return Standard

A number of parties cited case law, in addition to those cases already discussed in these Views of the Board, in their arguments regarding the determination of the cost of capital and the overall return. *Northwestern Utilities (1929)*, *Bluefield* and *Hope* are the leading cases with respect to the fair return standard. For ease of reference, the relevant passages are reproduced herein.

In *Northwestern Utilities (1929)* Lamont J. of the Supreme Court of Canada held that:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[24]

In *Bluefield*, the US Supreme Court stated:

> The company contends that the rate of return is too low and confiscatory. What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit

24 *Northwestern Utilities (1929), supra* note 9 at pp. 192-193

> and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[25]

Finally, in *Hope,* the US Supreme Court stated:

> We held in *Federal Power Commission v. Natural Gas Pipeline Co.*, that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its ratemaking function, moreover, involves the making of "pragmatic adjustments." And when the Commission's order is challenged in the courts, the question is whether that order "viewed in its entirety" meets the requirements of the Act. Under the statutory standard of "just and reasonable" it is the result reached not the method employed which is controlling. It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the Commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. And he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences.
>
> The rate-making process under the Act, i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. Case that "regulation does not insure that the business shall produce net revenues". But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. The conditions

25 *Bluefield, supra* note 10 at pp. 692-693

> under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at.[26] [citations omitted]

RH-1-70 was the first proceeding under Part IV of the Act in respect of tolls to be charged by TransCanada. In that Decision, the Board quoted extensively from, considered and relied upon these cases. The Board concluded as follows in respect of the framework for consideration of an appropriate rate of return for TransCanada:

> The Board is of the opinion that in respect of rate regulation, its powers and responsibilities include on the one hand a responsibility to prevent exploitation of monopolistic opportunity to charge excessive prices, and equally include on the other hand the responsibility so to conduct the regulatory function that the regulated enterprise has the opportunity to recover its reasonable expenses, and to earn a reasonable return on capital usefully employed in providing utility service. Further, it holds that to be reasonable such return should be comparable with the return available from the application of the capital to other enterprises of like risk. The Board accepts that, with qualifications, the rate of return is the concept perhaps most commonly used to project for some future period the ratio of return which has been found appropriate for the capital employed usefully by a regulated enterprise in providing utility service in a defined test period.[27]

In the RH-4-2001 Reasons for Decision, the Board set out what it viewed as the attributes which a fair return ought to have. One of the elements referred to was the appropriate balance of customer and investor interests. The Board went on to state that customer interest in rate of return matters relates most directly to the impact the approved return will have on tolls, and found this to be a relevant factor in the determination of a fair return.[28] In the RH-R-1-2002 Decision regarding TransCanada's application for review of RH-4-2001, the Board reiterated its view that the balance of interests between consumers and investors in the utility could be taken into account.[29] On appeal of this point, the Federal Court of Appeal in *TransCanada v. NEB* agreed with TransCanada's argument that the required rate of return on equity must be determined solely on the basis of the Mainline's cost of equity capital. The Court found that the impact of

26 *Hope, supra* note 11 at pp. 602-603

27 RH-1-70, *supra* note 13 at p. 7-5

28 RH-4-2001, *supra* note 4 at pp. 11-12

29 RH-R-1-2002, *supra* note 5 at p. 1

any resulting toll increases on customers is not a relevant consideration in that determination.[30] While consumers have an interest in ensuring that the Mainline's costs are not overstated and therefore may provide evidence, it must pertain to the costs of the Mainline. The Court noted that the Board could take increases in tolls into account in considering whether the tolls should be phased in over time to ameliorate any rate shock. The Court went on to find that there was no evidence that the Board took the impact on consumers into account in making its determination of the Mainline's return on equity[31] and the appeal was denied. The Board confirmed, in its 19 November 2004 ruling on a TransCanada motion (see Appendix III), that it would not give weight to any evidence pertaining to the impact of tolls on customers in making the determinations to be made in Phase II.

The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:

- be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);
- enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
- permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).

In the Board's view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable.

Methodology to Determine Capital Structure

The preceding discussion sets out the framework for the Board's consideration of the cost of capital issues. Different views were presented regarding which approach should be used in establishing the equity thickness, and to what determinations the fair return standard would apply.

IGUA argued that the RH-2-94 Decision includes a reassessment mechanism, based on criterion of significant change in business risk, which continues to apply. IGUA further argued that a motion to vary and set aside this feature of the RH-2-94 Decision was required but was not done in this case. In the Board's view, the wording in the RH-2-94 Decision established an expectation or desire on the part of the Board that

30 *TransCanada v. NEB, supra* note 8 at paras. 35-36

31 *Ibid.* at para. 37

the capital structure decision would endure for a period of years. The Decision further indicates that the Board would be prepared to consider a reassessment of capital structure in the event of a significant change in business risk, in corporate structure or in corporate financial fundamentals. In the Board's view, the wording of the RH-2-94 Decision was not an attempt to establish a standard that, if not met, would preclude an applicant from filing an application, but rather was an indication of when the Board believed it would be appropriate to reconsider the matter. Further, the Board determined in its rulings prior to the oral portion of this hearing that it would not limit the examination of the capital structure issues to any particular methodology. Thus, in the Board's view, a motion to vary the RH-2-94 Decision was not necessary.

TransCanada argued that the Board should make its determination on capital structure by examining the total return, as the Board must, as a matter of law, establish a fair overall return for the Mainline and it is to the overall return that the fair return standard applies. From that finding, the Board can determine the Mainline's equity component. Included in this approach is TransCanada's argument that the Board ought not to limit itself to examining changes in business risk since the last time the Mainline had its cost of capital assessed by the Board, in this case, in 2001, but rather should apply a clean-slate approach.

Many of the intervenors agreed that the Board is required to provide TransCanada a fair return, but disputed TransCanada's contention that the Board is obligated to look at the overall return when setting the Mainline's capital structure. Instead, the intervenors favoured the Board's traditional approach, wherein the Board first sets a return on equity and then undertakes an assessment of business and financial risks facing the pipeline. This type of assessment typically looks at how each component of business risk has changed since the last time business risk was assessed. The final step in this approach involves the establishment of a capital structure or a common equity ratio that, when combined with the ROE, will result in an overall return commensurate with the level of business risk facing the investment. Some intervenors referred to this as a purely arithmetic function.

While some parties seemed somewhat entrenched early on in this proceeding regarding whether it was proper for a party on the opposing side to present its case according to a particular methodology, most seemed to recognize, as the hearing progressed, that the law did not prohibit the other approach. The arguments tended to focus on which approach would be more appropriate for the Board to use in coming to a decision on capital structure. Other than establishing that the return awarded to the company must meet the fair return standard, the case law provides no assistance on how this must be done.

The Board agrees with CAPP and others that historically the Board has examined the elements that go into determining total return separately rather than looking at specific evidence regarding overall return. In the RH-2-94 Multi-Pipeline Cost of Capital Decision, the Board established the ROE for a benchmark pipeline to be applied to all pipelines in that hearing. It then determined that any risk differentials between the pipelines could be accounted for by adjusting the common equity ratio.[32] To do this, it started with an analysis of each pipeline's business risk and then examined factors such as financing requirements, the pipeline's size and its ability to access financial markets.[33]

In RH-4-2001, the Board considered but rejected TransCanada's ATWACC proposal. The Board held that its assessment of how the Mainline's business risk had changed since the consideration in the RH-2-94 Proceeding justified an increase in the Mainline's common equity ratio. The Board found in RH-4-2001, as it had in RH-1-70, that the determinations made were consistent with the legal principles set out therein, which included the fair return standard, and found that the decisions would result in a fair return for the Mainline.

The Board also agrees with TransCanada that the case law establishes that it is the overall return on capital to the company which ought to meet the comparable investment, financial integrity and capital attraction requirements of the fair return standard. However, this does not, in the Board's view, require that the Board make the necessary determinations solely by means of examining evidence on overall return.

Similarly, while it is open to the Board to look at changes in business risk since a previous decision to establish an equity thickness for the Mainline, it is also not restricted to this approach. When the Board utilizes the traditional methodology, it ensures that each element that goes into the determination of the overall return is reasonable. It then uses its judgment to ensure that the resulting return is a fair return in accordance with the legal requirements. To this extent, the return on capital is not simply an arithmetic determination of various elements. The Board must always apply its judgment to ensure the return on capital is fair.

In short, as indicated by the Federal Court of Appeal in *TransCanada v. NEB,* when the Board employs a cost of service methodology, it must faithfully determine the Mainline's costs based on the evidence and its own sound judgment.[34] Beyond that, the Board is not required in law to subscribe to any particular methodology.

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32 RH-2-94, *supra* note 1 at p. 6

33 *Ibid*. at p. 25

34 *TransCanada v. NEB*, *supra* note 8 at para. 32

Thus, the Board is neither limited to considering evidence pertaining to significant changes since it last established the Mainline's capital structure, nor is it compelled to give weight to particular evidence pertaining to overall return. The Board must consider all the evidence placed before it, decide what weight that evidence should be given and apply its judgment in making the required decisions. In doing so, the Board must satisfy itself that these decisions are consistent with the Act's requirement for just and reasonable tolls and that, since the Mainline operates under cost of service regulation, the return on capital to the company meets the fair return standard. In this hearing, the Board must apply its judgment to satisfy itself that the approved common equity ratio, when combined with the Mainline's ROE of 9.56 percent, will result in a fair return on equity for TransCanada in 2004.

What weight a specific piece of evidence or methodology should be given is a matter of judgment. In the following chapters of these Reasons for Decision, the Board has summarized the evidence and position of parties and expressed views concerning the weight that such evidence ought to be afforded in making the various determinations to be made in Phase II.

Chapter 3

Junior Subordinated Debentures

TransCanada introduced junior subordinated debentures (JSDs) into the Mainline's capital structure in 1997. The JSDs were included as a cost-effective alternative to preferred shares, which had previously been part of the Mainline's capitalization. The last comprehensive cost of capital hearing for the Mainline that preceded the conversion of the preferred shares to JSDs was RH-2-94, which initially applied to the 1995 Test Year. In that Decision, the Board concluded that "given current cost rates, it is appropriate for TransCanada to maintain preferred shares in its capital structure at the present time."[35] In 1995, preferred shares represented 9.96 percent of the Mainline's capitalization.

Two tranches of JSDs were issued by TransCanada and both were fully allocated to the Mainline: an 8.75% US$ 160 million issue (8.75% JSDs) in 1997, which was redeemed in 2003; and an 8.25% US$ 460 million issue (8.25% JSDs) in 1998, which TransCanada proposed to redeem in 2004. TransCanada submitted that JSDs have comprised approximately ten percent of the Mainline's total capitalization in the form of preferred securities since 1998. It proposed to replace this ten percent preferred component of the Mainline's capitalization with seven percent unfunded debt and three percent common equity.

TransCanada requested that the Board approve the elimination of the JSDs from the Mainline's capital structure and provide explicit direction on how TransCanada is to replace the JSDs. TransCanada noted that while the Board cannot direct TransCanada to call the JSDs, it can determine whether the costs incurred by the utility can be included in the Mainline's revenue requirement and recovered in tolls.

Position of TransCanada

TransCanada cited several benefits that would result from the proposed changes to the Mainline's capitalization. The removal of the US dollar-denominated JSDs would result in a sizeable one-time foreign exchange gain to shippers, simplify the Mainline's capital structure and reduce the Mainline's future exposure to foreign exchange risk and to further changes in accounting or credit rating agency treatment.

According to TransCanada, the JSDs are neither common equity nor debt but they provide equity support to senior debt. As a result, the proposed redemption of JSDs and their partial replacement with senior debt would require an offsetting increase in common equity in the Mainline's capital structure. TransCanada suggested that credit rating agencies typically give hybrid securities like JSDs 30 percent to 40 percent equity credit. The proposed Mainline capital structure for 2004 would reflect this treatment, incorporating an increase of seven percent senior debt and an increase of three percent common equity. TransCanada contended that it was not

35 RH-2-94, *supra* note 1 at p. 25

appropriate to redeem the JSDs and replace them with a like instrument, as the marketplace for these securities does not exist in Canada at this time.

TransCanada submitted that developments in credit assessment and accounting standards required changes in the preferred component of the Mainline's capital structure. According to TransCanada, credit rating agencies are taking a more critical view of the credit support that hybrid securities, such as JSDs, provide to senior debt. Further, the Canadian Accounting Standards Board announced that JSDs would likely be classified as debt under Generally Accepted Accounting Principles (GAAP) by the end of 2004. TransCanada submitted that the credit supporting attributes of JSDs have weakened and that these instruments are no longer well suited for their intended purpose of providing credit support.

If the Board were to approve a 40 percent equity ratio for the Mainline, in TransCanada's view, no further adjustments to the deemed equity ratio to reflect the redemption of the JSDs would be required. However, if the Board determined that the appropriate capital structure should include less than 40 percent equity, then the Board should make a determination with respect to the equity credit warranted as a result of the JSDs' redemption. TransCanada suggested that if the JSDs are redeemed, the equity ratio of the Mainline should be increased from 33 to 36 percent regardless of any findings the Board may make on business risk. TransCanada viewed a capital structure (assuming redemption of JSDs) consisting of 36 percent common equity and 64 percent senior debt as a different characterization of the status quo.

It its initial application, TransCanada proposed to make the effective date for redemption of the JSDs 30 June 2004. However, TransCanada acknowledged at the end of January 2005 that the JSDs had not been redeemed. TransCanada argued that the Board could provide guidance on this matter, while not purporting to make a decision in respect of 2005.

In response to CAPP's contention that the retirement of preferred securities was factored into the RH-4-2001 Decision, TransCanada noted that the Decision makes no mention of preferred securities and pointed out that the three percent increase in common equity approved by the Board in RH-4-2001 was attributed to increased business risk.

Position of Intervenors

CAPP submitted that the JSDs were treated as debt by the Board in its RH-4-2001 Decision, and should continue to be treated as debt. CAPP further submitted that JSDs are interest-bearing instruments and are in substance debt. It argued that, although there is potentially a large one-time foreign exchange gain as a result of redeeming the JSDs, the replacement of the JSDs with a combination of debt and common equity is a more costly solution. Therefore, CAPP submitted that TransCanada should either leave the JSDs in place or replace them with a similar instrument. The terms and conditions of the replacement debt, in CAPP's view, is a matter for the prudent exercise of management judgment.

CAPP rejected TransCanada's contention that there is a ten percent preferred securities layer in the Mainline's capital structure and noted that the amount of JSDs in the Mainline's capital structure is a matter of arithmetic, based on the dollar value of JSDs that happen to be in the capital structure at any given time. CAPP noted that JSDs currently comprise approximately 8.5 percent of the Mainline's capitalization.

It was noted by CAPP that TransCanada did not seek approval from the Board when it redeemed the 8.75% JSDs in 2003, and that this redemption had an effect on the capital structure of the Mainline. CAPP further noted that TransCanada had intended to discuss this issue with the Mainline's Tolls Task Force (TTF) in due course, but chose to act unilaterally. CAPP took issue with TransCanada's position that the company was acting altruistically to the benefit of shippers in redeeming the JSDs in 2003. CAPP contended there was no urgency in making this change to capital structure, and the TTF should have been consulted. CAPP further suggested that the motivation for this action was to move the Mainline out of a pre-funded position, which benefited TransCanada.

CAPP indicated that JSDs rank behind senior debt both in terms of interest and any winding up of claims in a bankruptcy proceeding. CAPP pointed to a presentation where Standard and Poor's (S&P) had stated that the Mainline's capital structure is comprised of 33 percent common equity and 67 percent debt, in support of CAPP's view that S&P does not acknowledge equity credit for the JSDs. Further, CAPP submitted that the Board was aware of the Mainline's previous use of preferred shares but did not regard them as common equity and specifically set the Mainline's capital structure at 33 percent common equity and 67 percent debt, including the JSDs in the debt component, with no equity characteristics. CAPP contended that the Board recognized that within the debt class there were a variety of different types of debt, but all were classified as debt.

The fact that the JSDs had not been redeemed as of January 2005 made it difficult, in CAPP's view, to retroactively apply for their redemption. CAPP suggested that the benefits, if any, of a change to capital structure would have to be applied on a prospective basis.

IGUA and Coral endorsed the submissions of CAPP on the JSDs. Coral also suggested that the Board has the option of leaving it to TransCanada to manage the JSDs allocated to the Mainline or of approving TransCanada's request to replace the JSDs with senior debt and common equity. Coral submitted that the latter option would leave shippers worse off.

Ontario expressed the view that as redemption of the JSDs had not taken place during the 2004 Test Year, it would be improper for the Board to make any adjustment to the Mainline's deemed equity structure in respect of the JSDs for 2004.

Views of the Board

The Board is of the view that hybrid securities, like the JSDs, may provide credit support to senior debt. However, it appears that, as TransCanada has acknowledged, the credit support provided by the JSDs has declined since they were issued in the late 1990s. The Board notes there is no consensus amongst credit rating agencies regarding the precise amount of equity credit given to TransCanada's JSDs.

The Board notes that in the RH-4-2001 Decision, the JSDs were considered part of the Mainline's debt,[36] and that their cost rate was factored into the calculation of the overall cost of debt for the Mainline. The Board views coverage of all fixed charges, whether interest on debt or dividends on preferred shares, as equally important. Therefore, it is appropriate to treat all fixed income securities as forming part of the debt components of the Mainline's capital structure. This is accomplished by focusing on establishing the appropriate equity ratio for the Mainline, rather than making specific findings on the composition of the debt.

The Board notes that in the past, it has assessed the business risk of the pipelines it regulates and reflected these relative risks through the deemed common equity component of the pipelines' capital structures. For example, in the RH-2-94 Decision, the Board stated:

> The Board recognizes that the gas pipelines have some individual characteristics, described in its views above, which differentiate one from another. On balance, however, the Board is of the view that the overall business risks of TransCanada, Foothills, ANG and TQM balance out such that a similar common equity ratio can be given to these four pipelines. Accordingly, the Board approves a common equity ratio of 30% for TransCanada, Foothills, ANG and TQM.[37]

Also in RH-2-94, having set a common equity ratio of 30 percent for the Mainline, the Board approved the maintenance of preferred shares in the Mainline's capital structure, noting that:

> With respect to preferred shares, the Board concludes that, given current cost rates, it is appropriate for TransCanada to maintain preferred shares in its capital structure at the present time.[38]

In the Board's view, the issue related to preferred securities has been one of cost efficiency, not one of credit support, as the same common equity ratio was approved in RH-2-94 for pipelines of similar risk, regardless of whether the pipelines had preferred shares in their capital structures. Consistent with this view, the Board will, in this instance, set a common equity ratio that is appropriate when combined only with debt. Should hybrid securities form part of this debt and provide further support for senior debt, the Board would consider this reasonable so long as it is cost effective. The Board views the minimization of costs, including financing costs, as an objective of reasonable and prudent management.

36 RH-4-2001, *supra* note 4 at p. 59

37 RH-2-94, *supra* note 1 at p. 27

38 *Ibid*. at p. 25

While the Board notes TransCanada's submission concerning the potential for a large one-time foreign exchange gain to be realized through redemption of the JSDs, the Board is of the view that the long-term benefits to Mainline shippers are less certain, given uncertainty over the future cost rates of the securities that would replace the JSDs. TransCanada stated that its goals were to simplify the Mainline's capital structure, reduce its exposure to currency fluctuations and accommodate changes in accounting standards. The Board is of the view that these are all reasonable objectives, but that TransCanada can manage the associated risks without the Board providing an express direction in regard to the redemption or retention of the JSDs.

The Board is not prepared to direct that the JSDs be eliminated from the Mainline's capital structure. The JSDs are as cost effective as the rest of the Mainline's embedded senior debt, and therefore, the Board sees no reason to direct that they be removed from the Mainline's capital structure. The Board also notes that, although TransCanada's application was for the 2004 Test Year, the company did not redeem, although it could have redeemed, the JSDs in 2004. Therefore, for rate-making purposes, the JSDs should continue to form part of the Mainline's funded debt for 2004.

TransCanada has the discretion to redeem the JSDs or maintain them in the Mainline's capital structure. The Board will continue to treat the JSDs as part of the Mainline's debt. On a prospective basis, should the JSDs be redeemed, the Board anticipates that no changes to the Mainline's equity ratio would be warranted. As always, TransCanada's future decisions concerning the JSDs may be subject to scrutiny on the basis of prudence.

Decision

The 8.25% JSDs shall remain part of the Mainline's funded debt for the 2004 Test Year.

Chapter 4

Business Risk

The business risk of a pipeline is a key determinant in the analysis of an appropriate capital structure. In these Reasons for Decision, the discussion of business risk has been divided into an assessment of supply risk, market risk, regulatory risk, competitive risk and operating risk. The various forms of risk are related, and the boundaries between them are subjective. What one party may consider a source of market risk may be viewed by another as part of competitive risk. To avoid duplication, each concept is presented under only one form of risk, although it might have been discussed by parties under various forms.

4.1 Approach to Business Risk

Position of TransCanada

TransCanada submitted that the determination of capital structure must be made on the basis of all the evidence relating to the Mainline in 2004, not just changes since RH-4-2001. However, it acknowledged that in some areas, notably with regard to supply, changes since RH-4-2001 are relevant. TransCanada argued that the Board does not have to identify changes since 2001 or conclude that the Board was wrong in RH-4-2001 to grant TransCanada's request in this proceeding.

Position of Intervenors

CAPP contended that the relevant focus of this proceeding is to determine what of significance has changed since RH-4-2001 to justify a change in capital structure, since issues which arose prior to that had been dealt with in that proceeding. CAPP submitted that TransCanada's key messages related to business risk are the same as those which were presented in RH-4-2001. CAPP claimed that issues around supply, markets, competition and regulation have not raised the Mainline's business risk since 2001 and submitted that TransCanada has provided nothing to demonstrate any significant change since that time.

IGUA argued that the significant change of circumstances test identified in the RH-2-94 Decision should apply to this proceeding and contended that there is insufficient evidence to show a significant change since RH-4-2001.

Coral submitted that TransCanada has not made a case that there has been any meaningful change in its business risk since 2001 or that the Board misconceived the situation in its RH-4-2001 Decision.

Ontario argued that the changes in business risk since RH-4-2001 that were identified by TransCanada, that is, changes related to supply, market growth, development of liquefied natural gas (LNG) alternatives and the contractual underpinnings of the Mainline, have not materially increased since RH-4-2001.

4.2 Supply Risk

Supply risk is the risk that the physical availability of natural gas could affect the Mainline's income-earning capability.

Position of TransCanada

TransCanada argued that supply risk is a significant long-term issue because there is flat to declining supply from the Western Canada Sedimentary Basin (WCSB) and there is competition for that supply. The issue of competition for supply is also discussed in Section 4.5, Competitive Risk.

To explore what TransCanada viewed as a plausible range of natural gas supply and Mainline throughput outcomes, TransCanada prepared a throughput study which took into consideration scenarios for conventional and unconventional WCSB supply, Mackenzie Delta supply, western Canadian gas demand, export capacity expansions and allocation of available supply to ex-WCSB pipelines, including the Mainline. The throughput study initially consisted of three cases: Base, Low and High. Following information requests, the Alaskan-in and Distress cases were also added.

Conventional Supply

TransCanada stated that there is a high probability that conventional production has peaked or will peak in the next several years. TransCanada suggested that the sustainability of supply from the WCSB in the long term is primarily dependent on the ultimate potential and presented estimates of conventional economic resources ranging from 7 082 10^9m^3 (250 Tcf) for the Low Case to 8 498 10^9m^3 (300 Tcf) in the High Case. TransCanada's estimates for economic and technical resources are shown in Table 4-1.[39]

Table 4-1
TransCanada's Estimate of Conventional WCSB Ultimate Potential
10^9m^3 (Tcf)

	Base Case	**Low Case**	**High Case**
Technical Resources	8 527 (301)	7 620 (269)	9 405 (332)
Economic Resources	7 790 (275)	7 082 (250)	8 498 (300)

TransCanada argued that its main point of divergence with CAPP with respect to conventional supply was the plausibility of TransCanada's Low Case. TransCanada stated that the Low Case in the throughput study is primarily a low ultimate potential case and is not driven by a change in the natural gas price forecast from the Base Case. TransCanada asserted that CAPP's statement that the Low Case for conventional ultimate potential has a high probability of being exceeded

39 A definition of technical and of economic resources appears in the glossary of terms.

should be rejected because the ultimate potential used in the Low Case is well within the range of estimates of other organizations.[40] Based on recent WCSB performance and recent assessments of ultimate potential, TransCanada stated that outcomes at the low end of the plausible range of outcomes are more likely today than in 1995. Therefore, supply cases at the lower end of the range should be given serious consideration in an assessment of business risks.

Unconventional and Northern Supply

TransCanada submitted that both unconventional gas (expected to be comprised mainly of coalbed methane and tight gas[41]) and northern gas have higher risk profiles than conventional supply. As there is currently no significant Canadian unconventional production, future production levels represent a critical forecast uncertainty. Although these sources of supply are of higher risk than conventional sources, large volumes have been included in the Base Case. TransCanada noted that gas from the Mackenzie Delta is included in all throughput study cases even though the Mackenzie Valley Pipeline has not received regulatory approval.

While TransCanada viewed the probability of Alaskan gas coming on-stream as greater now than in the past, it submitted that there is still considerable uncertainty about whether that gas would flow on the Mainline. Further, TransCanada stated that there is a risk that LNG development may capture the market to which Alaskan gas would otherwise flow. Therefore, it viewed Alaskan gas as too speculative to include in any of the initial throughput study cases.

TransCanada claimed that its purchase of the remaining shares of Foothills was an option to increase the likelihood of TransCanada's involvement in the North. While it may directionally improve the probability that the Mainline captures northern gas, it does not increase the probability that an Alaskan pipeline will proceed.

Capacity Additions and Allocation of Natural Gas Supply

Once total supply was determined for each of the throughput study cases, natural gas demand in western Canada was deducted to arrive at an estimated volume available for export from the region. Next, TransCanada estimated any additional pipeline capacity additions necessary to keep overall pipeline utilization from western Canada at approximately 90 percent. In the Low, Base and High Cases, these additions totalled 9.9 $10^6m^3/d$ (350 MMcf/d), 15.6 $10^6m^3/d$ (550 MMcf/d) and 56.7 $10^6m^3/d$ (2.0 Bcf/d) respectively. The Alaska-in case assumed that a total of 83.6 $10^6m^3/d$ (2.95 Bcf/d) of new ex-WCSB export capacity would be in service by 2011-2012 to transport WCSB and northern gas. New pipeline capacity was assumed to come into service supported by 15 year firm contracts.

40 TransCanada cited: National Energy Board - Canada's Energy Future: Scenarios for Supply and Demand to 2025 (2003) and National Energy Board - Canada's Conventional Natural Gas Resources: A Status Report (April 2004); Canadian Energy Research Institute; and the Canadian Gas Potential Committee.

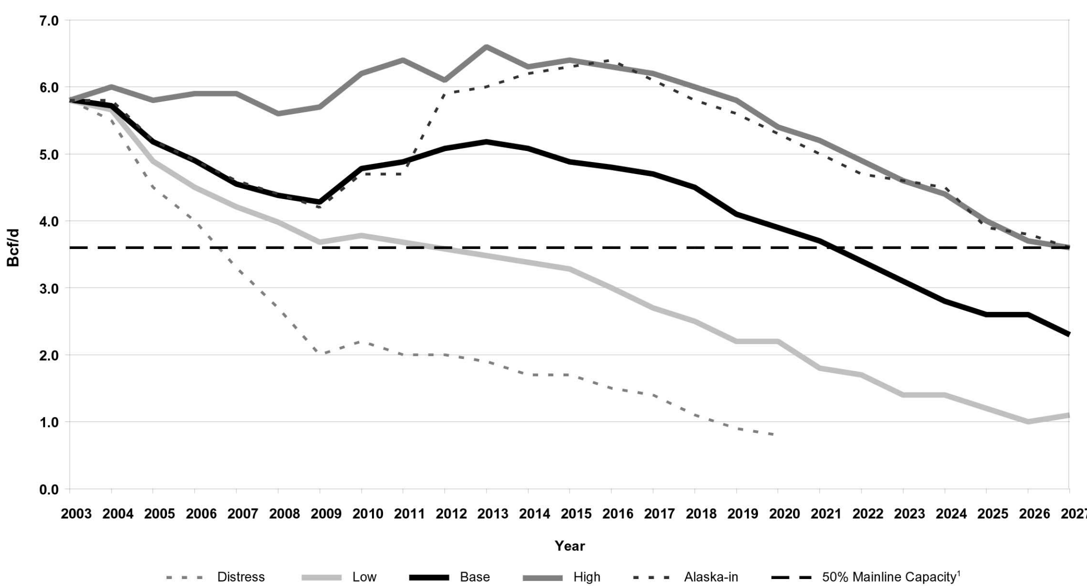
41 Coalbed methane is natural gas, primarily methane, found in most coal seams. The methane is created during coalification, the natural process that converts organic matter into coal over time. Tight gas is natural gas contained in low permeability reservoirs.

TransCanada allocated export volumes first to pipelines with firm contracts and then to the pipelines with the highest netbacks to western Canada. TransCanada applied historical utilization factors to set the upper limit of flow on each pipeline and then allocated the remainder of the supply to the Mainline. At the time that western Canadian export volumes begin to decline, throughput on all pipelines not protected by long-term firm transportation contracts was assumed to decline proportionally to the pipeline's share of ex-WCSB export volumes. TransCanada submitted that this assumption is likely to lead to higher assumed throughput on the Mainline than will actually occur given that it views the Mainline as the swing pipeline, attracting only throughput that does not have the option of flowing on other systems.

Results of Throughput Analysis

The resulting total western supply and Mainline throughput forecasts for selected years are presented in Appendix IV. The throughput forecasts for the entire period are also illustrated in Figure 4-1. In the Base Case, total supply available to the Mainline is expected to decline until northern gas commences flow in 2010 and then resume its decline after 2013. In the Low Case, supply available to the Mainline falls steadily over the forecast period.

Figure 4-1
TransCanada's Throughput Forecasts



1 The horizontal line in Figure 4-1 indicates 50 percent of Mainline capacity. The time at which throughput declines to 50 percent of capacity was raised by CAPP in this proceeding and relied on by TransCanada in RH-1-2002 as an indicator of the Mainline's economic life.

TransCanada argued that CAPP's throughput sensitivity, which removed the assumption that the Mainline offered the lowest netbacks and showed no additional capacity being built except in the High Case, resulted in unacceptably high utilization rates, with aggregate utilization out of the basin exceeding 96 percent in the High Case.

Changes in Supply Risk since RH-4-2001

Given the recent experience of little production growth despite high prices, TransCanada contended that supply risk has increased since RH-4-2001. TransCanada also submitted that forecasters are now expecting lower levels of peak production as well as lower ultimate resources. TransCanada pointed out that its Base Case WCSB peak production is now forecast to be 482 $10^6 m^3/d$ (17 Bcf/d) compared with 555 $10^6 m^3/d$ (19.6 Bcf/d) in its Base Case presented in RH-4-2001. TransCanada's economic ultimate potential estimates have also been reduced since RH-4-2001. Overall, the Base Case Mainline throughput for the year 2020 is now forecast to be 37 percent lower than it was at the time of RH-4-2001.

Depreciation and Supply Risk

TransCanada acknowledged that the Mainline's depreciation rate was increased in 2001 and 2002 as part of a negotiated settlement, and in 2003 through the RH-1-2002 Decision.[42] With respect to the suggestion that the higher depreciation rates approved since 2001 offset supply risk, TransCanada noted that depreciation does not provide any compensation for bearing the risk that the Mainline may not be able to recover its prudently incurred costs, including the return on investment, over its economic life. TransCanada agreed with the Board's statement in the RH-4-2001 Decision that depreciation expense is intended to allow recovery of capital over the economic life of the assets, while return on capital compensates for the risk that the economic life and other depreciation parameters may be wrong.[43]

TransCanada suggested that the assumption that goes into the determination of return is that the depreciation rate is set correctly, so that the return of capital will occur over the economic life of the asset. Accordingly, TransCanada submitted that setting the depreciation rate correctly does not compensate for a fundamental increase in business risk, although setting a depreciation rate that is either too high or too low affects business risk.

While TransCanada accepted that risk is higher if depreciation is assessed infrequently than if it is assessed frequently, it contended that regular assessment of the depreciation rates does not mitigate risk. TransCanada stated that even if the depreciation rate is correct, regular updates do not eliminate future uncertainty associated with it at present.

In addition, TransCanada suggested that there is a risk that the depreciation rate will not be changed when circumstances warrant. Further, TransCanada contended that even if the regulator were willing to allow higher depreciation rates in the case of a deterioration in the supply outlook, the compounding effect on tolls of lower throughput and higher depreciation rates may make tolls uncompetitive.

TransCanada acknowledged that the level of plant remaining undepreciated is potentially relevant to an assessment of business risk and there would not be any recovery risk left if the asset was fully depreciated. However, TransCanada suggested that there is considerable

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42 National Energy Board RH-1-2002 Reasons for Decision, TransCanada PipeLines Ltd. (Tolls and Tariff), July 2003 [hereinafter RH-1-2002]

43 RH-4-2001, *supra* note 4 at p. 28

uncertainty concerning the level of plant remaining at the end of the assumed economic life and the amount of unrecovered capital could still be considerable at that point.

In addition, TransCanada contended that the depreciation rates set in the RH-1-2002 Decision are, if anything, conservative because they contain no allowance for negative terminal salvage costs and because the existing 25 year economic planning horizon is optimistic.

Position of Intervenors

CAPP acknowledged that TransCanada's Base Case forecast of total conventional supply was reasonable and reflective of current knowledge. CAPP considered the High Case as achievable under the right conditions. However, CAPP was of the view that, given current and anticipated levels of demand and correspondingly strong prices, as well as the decline experienced by various US basins, the possibility of conventional supply volumes being lower than TransCanada's Low Case was remote.

While CAPP agreed that views on supply have changed since RH-4-2001, CAPP stated that this does not by itself translate into increased business risk for TransCanada. CAPP submitted that the more rapid recovery of capital resulting from increased depreciation rates that were approved in RH-1-2002 for 2003, and agreed to in a negotiated settlement for 2001 and 2002, offset the change in supply and throughput outlook since RH-4-2001. CAPP stated that the Board identified two factors for shortening the capital recovery period in RH-1-2002: the potential for lower supply outcomes and the comparability with competitors' depreciation lives. Consequently, CAPP contended that shippers should not have to pay for the same supply risk twice, once through higher depreciation and again through higher return on capital.

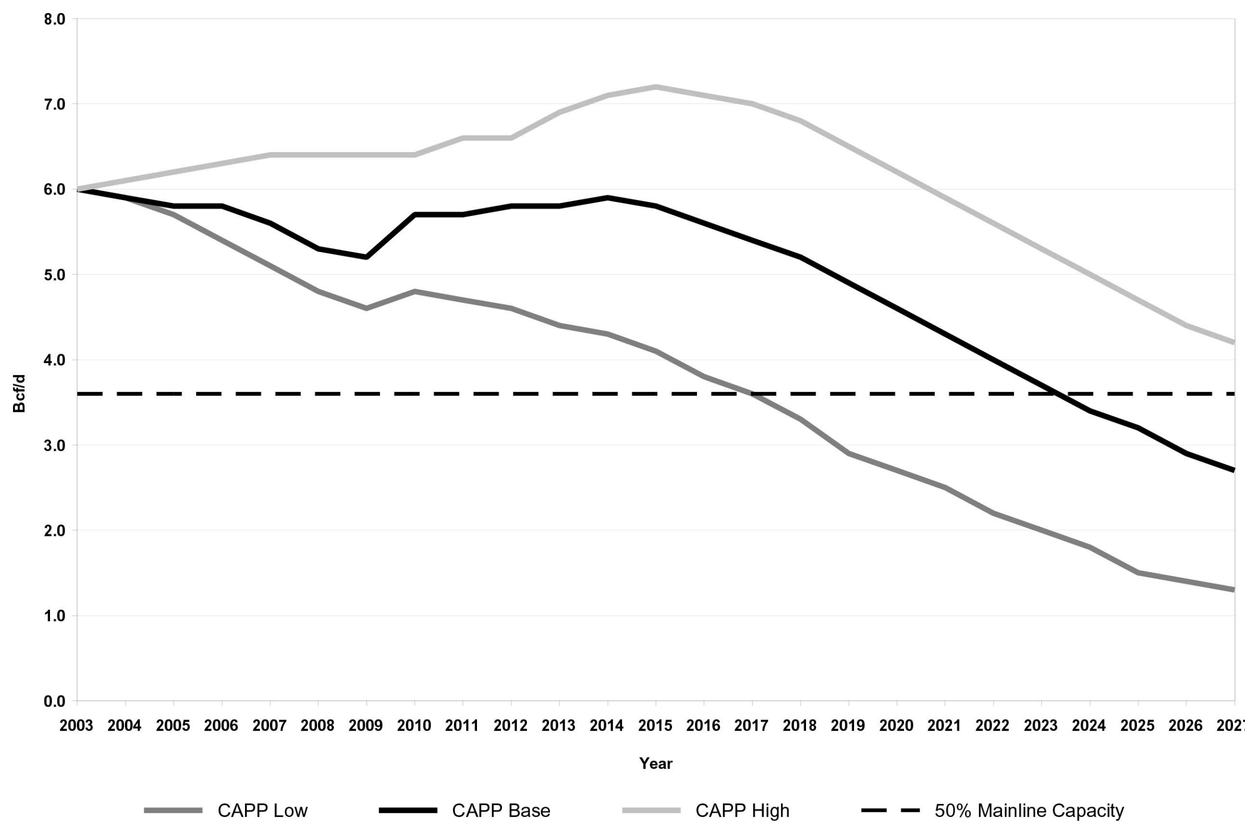
It was noted by CAPP that in the RH-1-2002 Decision, the Board stated its expectation that depreciation would be assessed regularly. CAPP suggested that if supply declines more rapidly than anticipated, depreciation rates could be increased in response. CAPP observed that as the pipeline depreciates, the level of capital remaining to be recovered declines, thereby reducing business risk.

CAPP also considered that the development of the North (Mackenzie Valley and Alaska), the development of unconventional gas and the shift to deeper parts of the WCSB are positive developments which indicate that the market is working and supply is responding.

CAPP did not view Alaskan gas as too speculative to consider in this proceeding but acknowledged that the timing of this gas coming on stream would depend on prevailing market conditions. CAPP further acknowledged that producers are working on many options with respect to the flow of Alaskan gas. CAPP contended that TransCanada's actions in regard to Alaska, including the purchase of Foothills, suggest that Alaskan gas should be given greater weight as upside potential since it, along with unconventional gas, represents a significant upside opportunity for which TransCanada is well positioned to compete. CAPP stated that Alaskan gas was included in the throughput study in 2001 and the probability of the Alaska pipeline proceeding and of Alaskan gas flowing through the Mainline is higher now than it was in 2001. CAPP argued that TransCanada had minimized this upside potential. However, CAPP submitted that its view of supply risk does not depend on the inclusion of Alaskan gas.

With respect to TransCanada's throughput study, CAPP contended that the assumptions that the Mainline offers the lowest netback, and that additional pipeline capacity will be added in all cases, result in conservative estimates of Mainline throughput. CAPP prepared sensitivities to TransCanada's Base, High and Low Cases, removing TransCanada's assumption that the Mainline offers the lowest netback. Volumes were allocated to each pipeline based on historical throughput, calculated using 2000/01, 2001/02 and 2002/03 data, and assuming that no additional capacity would be added except 14.2 $10^6 m^3/d$ (500 MMcf/d) in the High Case. All other assumptions were those used by TransCanada in its throughput study. The results are shown in Figure 4-2 and the resulting total western supply and Mainline throughput sensitivities for selected years are presented in Appendix IV. The horizontal line in Figure 4-2 indicates 50 percent of Mainline capacity. CAPP noted that the time at which throughput declines to 50 percent of capacity was relied on by TransCanada in RH-1-2002 as an indicator of the Mainline's economic life.

Figure 4-2
CAPP's Throughput Sensitivities



The dates at which the Mainline throughput reaches 50 percent of capacity under TransCanada's five cases and the three CAPP sensitivities are shown in Table 4-2.

Table 4-2
Year when Mainline Throughput Declines to 50 percent of Capacity

	Distress	Low	Base	High	Alaska-in
TransCanada's Forecasts	2007	2012	2022	2027	2027
CAPP's Sensitivities	n.a.[1]	2017	2024	>2027	n.a.

1 Not available

Ontario argued that the probability of Alaskan gas flowing has increased and therefore the exclusion of Alaskan gas in TransCanada's throughput study was unreasonably negative. Ontario submitted that TransCanada's view of Alaskan gas being too speculative to consider in this proceeding was inconsistent with its action in other forums where it expressed more optimism.

4.3 Market Risk

Market risk has two aspects: the business risk that results from the overall size of the market and that which results from the pipeline's ability to capture market share. In these Reasons for Decision, the issue of market share is discussed under Section 4.5, Competitive Risk.

Position of TransCanada

While TransCanada stated that it is loss of market share due to competition, not shrinking demand, which drives its assessment of market risk, it did point out that projections of natural gas demand growth to 2015 are lower now than at the time of the RH-4-2001 Proceeding.

Position of Intervenors

CAPP suggested that the Mainline's market risk is low given that the North American gas market is growing and that much of that growth is in areas served by the Mainline. According to CAPP, expanding markets suggest the downturn in the Mainline's throughput over the last several years will prove only temporary.

Ontario argued that the possibility of uncertainty in demand growth in downstream markets was identified in RH-4-2001 and is not a new risk. Ontario pointed out that TransCanada is forecasting strong growth in natural gas markets.

4.4 Regulatory Risk

Regulatory risk is the risk to the income-earning capability of the assets that arises due to the method of regulation of the company.

Position of TransCanada

TransCanada expressed the view that the Mainline's regulatory risk has increased through the 1980s and 1990s with the evolution of the Board's policy on the certification of new pipelines. TransCanada contended that regulators' and policy makers' encouragement of greater competition and acceptance of the efficacy of market forces resulted in the approval of the Alliance Pipeline Ltd. (Alliance) facilities in advance of available supply and represented a fundamental change in the pipeline industry.

TransCanada maintained that, while it is true that the Mainline has not seen the costs of underutilization reflected in its earnings, if supply becomes inadequate or competitive alternatives become available, tolls may increase to the point where load is driven off the system and bypasses of the Mainline become economic. Regulators may be unable to mitigate the risk if tolls reach the point of driving load off the system. Further, TransCanada pointed to the Board's RH-1-2001 Decision, which stated that "some sharing of risk between TransCanada and its shippers may be appropriate if considered on a prospective basis",[44] in support of the view that there is no guarantee that the regulator will continue to employ a traditional cost of service model or that the Mainline will not be required to share in the costs of underutilization in the future. Additionally, the last decade has seen widespread use of negotiated settlements, many of which include features intended to substitute certain aspects of competitive markets for the traditional cost of service model.

With respect to CAPP's contention that regulatory risk may have declined since 2001 because TransCanada is no longer discussing a new regulatory model, TransCanada argued that no change in the regulatory model could have happened without regulatory approval and the proposal was never put before the regulator because of universal opposition.

Position of Intervenors

CAPP contended that there has been no substantial change in regulatory risk since 2001 and any minor regulatory uncertainty faced by the Mainline before 2001 was reflected in the RH-4-2001 Decision. If anything, CAPP asserted that regulatory risk has decreased because at the time of RH-4-2001, TransCanada and its stakeholders were discussing a new business and regulatory model for the Mainline. The uncertainty created by that discussion is now gone.

CAPP expressed the view that the NEB regulatory approach not only covers short-term regulatory risk, but also provides a long-term predictable and secure regulatory foundation for the Mainline while adapting to change in a prospective and balanced manner. CAPP suggested that the annual toll adjustments and predictable returns are the manifestation of a long-term bargain. Features such as cost of service revenue protection, deferral accounts, rolled-in pipeline costs for expansions and absence of volume or load factor risk limit the business risk faced by the Mainline due to regulatory uncertainty, as they have for the past 15 years or more.

Ontario also asserted that any regulatory changes were well known at the time of RH-4-2001 and there have been no developments since that time to increase the Mainline's regulatory risk.

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44 RH-1-2001, *supra* note 3 at p. 14

4.5 Competitive Risk

Competitive risk refers to the business risk that results from competition for customers at both the supply and market ends of the pipeline system. While it directly affects business risk by providing customers with alternatives to ship or purchase natural gas, it also indirectly affects market and supply risk. In these Reasons for Decision, all aspects of risk associated with competition for customers are discussed as part of competitive risk.

For ease of reference, Figure 4-3 presents a map of selected Canadian and US pipelines referred to in this section and in Chapter 5 of these Reasons for Decision.

Position of TransCanada

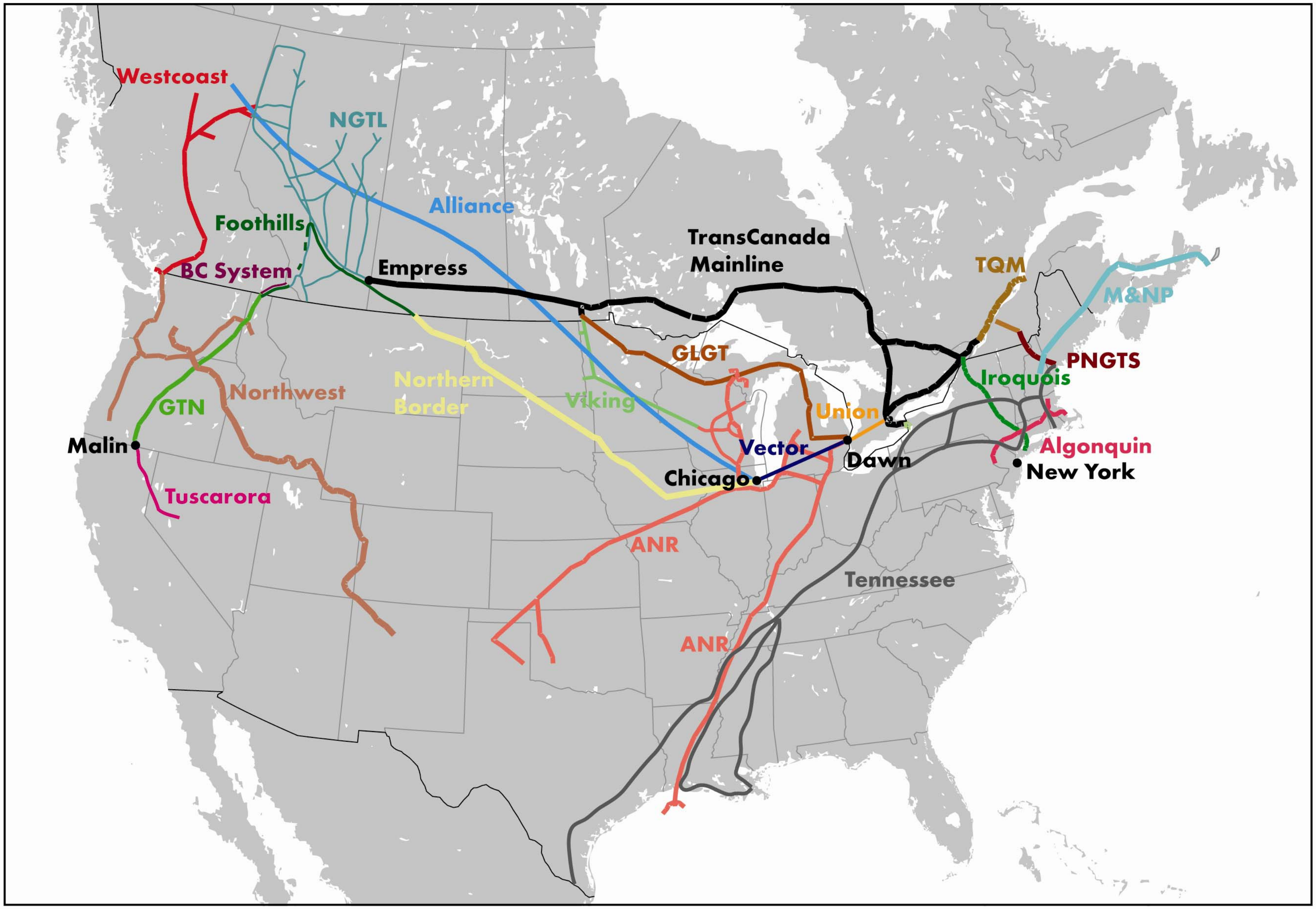
According to TransCanada, the entry of new pipelines has resulted in increased business risk for the Mainline and in the actual realization of that risk. Further, TransCanada submitted that the Mainline has been affected to a greater degree than other pipelines because it has a smaller proportion of long-term contracts and those contracts have shorter terms; it has been denied tools to compete, including pricing discretion, term differentiated rates and changes to contract renewal policies; and it has the poorest netbacks. As a consequence of these factors, the contractual underpinning of the pipeline, in particular billing determinants, has weakened, as shown in Table 4-3.

Table 4-3
Mainline Contract and Throughput Information
(As of September 2004)

	Contract		Throughput	
	Long-term Firm Daily Contract Quantities as of January (million GJ/d)	**Billing Determinants Firm Volume/Distance** (billion GJ-km)	**Firm & Non-Firm Volume/Distance** (billion TJ-km)	**Total Annual Average Daily Deliveries** (million GJ/d)
1998	7.9	17.1	6.2	7.6
1999	n.a.[1]	17.8	6.4	7.9
2000	7.8	17.7	6.1	7.8
2001	n.a.	14.7	5.5	7.1
2002	6.6	13.9	6.1	7.6
2003	n.a.	13.1	5.0	7.7
2004	7.1	12.0	5.0	7.8
2005	7.6	n.a.	n.a.	n.a.

1 Not available

Figure 4-3
Selected Canadian and US Pipelines



TransCanada claimed that the Mainline offers, and will continue to offer, a relatively less attractive netback compared with other ex-WCSB pipelines because of its greater distance to market. In support of this view, TransCanada provided an analysis which forecast netbacks over the period 2003 to 2025 for the six export routes that TransCanada viewed as the most relevant (see Table 4-4). Given its perception that the Mainline's netbacks are the lowest, TransCanada sees itself as the swing pipeline, attracting only the residual WCSB supply that does not flow elsewhere under contract or cannot move to markets offering better netbacks because of capacity constraints. TransCanada stated that parties would contract on the pipeline that has the lowest transportation cost. When asked about the relatively greater decontracting that occurred on other pipelines in the 2004/2005 contract year, TransCanada clarified that the swing pipeline hypothesis referred to flows on the system and not necessarily contracting.

Table 4-4
TransCanada's Netback Analysis
(Cdn$/GJ)

	2003		2004		2005	2004-2025
	Forecast	Actuals	Forecast	Actuals To July	Forecast	Average Forecast
Original six routes submitted by TransCanada:						
NGTL[1]/Mainline to Eastern Zone [2]	6.29	5.59	5.11	5.89	4.29	5.44
NGTL/Mainline/GLGT/TransCanada St. Clair to Dawn	6.44	5.74	5.27	6.13	4.45	5.59
Alliance to Chicago	6.65	5.86	5.45	6.14	4.55	5.54
NGTL/Foothills/Northern Border	6.68	5.88	5.49	6.22	4.60	5.58
NGTL/Mainline to Iroquois/Iroquois[3]	6.53	5.68	4.96	6.30	4.08	5.29
NGTL/BC System/GTN to Malin	6.40	5.46	5.46	5.67	4.62	5.76
Routes provided upon request:						
NGTL/Mainline to Dawn using Southwest Zone Toll	6.49	*5.78*[4]	5.31	*6.12*[4]	4.48	5.64
Alliance/Vector to Dawn	6.36	5.69	5.17	5.90	4.35	5.49
NGTL/Foothills/Northern Border/Vector	6.40	5.70	5.21	5.98	4.40	5.53
NGTL/Mainline to Niagara/Tennessee	6.93	6.09	5.37	6.68	4.49	5.71
Alliance/Vector/TransCanada Dawn to Niagara/Tennessee[5]	6.82	6.00	5.25	6.50	4.37	5.57
NGTL/Foothills/Northern Border/Vector/TransCanada Dawn to Niagara/Tennessee	6.86	6.01	5.29	6.58	4.42	5.61
Alliance/Vector/TransCanada Dawn to Iroquois/Iroquois	6.21	5.40	4.64	5.92	3.77	4.96
NGTL/Foothills/Northern Border/Vector/TransCanada Dawn to Iroquois/Iroquois	6.25	5.41	4.69	6.00	3.82	5.00
NGTL/Mainline/Viking[6]/ANR[7] to Chicago	6.43	5.64	5.25	5.98	4.37	5.34
NGTL/Mainline/GLGT/ANR to Chicago	6.42	5.62	5.23	5.94	4.34	5.29
Westcoast/Northwest Pipeline[8]/GTN to Malin	6.23	5.28	5.29	5.51	4.46	5.59

Bolding of routes indicates those using the Mainline
1 NOVA Gas Transmission Ltd.
2 Using Dawn Prices
3 Iroquois Gas Transmission System
4 Calculated using a $0.16/GJ differential between the Eastern Zone and the Southwest Zone Tolls and difference in fuel cost as provided by TransCanada
5 Tennessee Gas Pipeline Company
6 Viking Gas Transmission Company
7 ANR Pipeline Company
8 Northwest Pipeline Corporation

In response to information requests, TransCanada provided netbacks on additional routes beyond the original six, but submitted that some of these routes were not meaningful since they were little used. TransCanada also contended that the competitiveness of Alliance and Northern Border Pipeline Company (Northern Border) should be evaluated by comparing the netbacks from the primary destination on these pipelines, the Chicago, Illinois region, rather than the netbacks from gas flowing further downstream.

TransCanada contended that it was appropriate to use the Dawn, Ontario price with the Eastern Zone toll since the Dawn price is broadly indicative of prices further east. TransCanada stated that even though prices at the Niagara and Iroquois (Waddington, New York) export points are generally higher than at Dawn, the market at those points is not particularly liquid.

To address criticism of the netback study, in its reply evidence, TransCanada provided netbacks for the original six routes, using the April 2004 price forecasts of Energy and Environmental Analysis Inc. This analysis showed three Mainline netbacks as being lower than netbacks on Alliance or Northern Border from Chicago or netbacks on Gas Transmission Northwest Corporation (GTN) from Malin, California.

TransCanada did not regard a substantial portion of its market as being captive, given that deliveries are increasingly being sourced in the Chicago area and only flow on the Mainline for a short distance. Further, TransCanada submitted that Alliance and Vector Pipeline (U.S.) (Vector) can be easily and inexpensively expanded and toll increases due to non-renewals on the Mainline make potential alternatives increasingly attractive and feasible.

Other factors that TransCanada viewed as affecting its long-term competitive position include its outstanding deferred tax balance arising from using flow-through tax methodology, which TransCanada asserts puts it at a competitive disadvantage compared with its US competitors; absence of provision for terminal negative salvage in its depreciation rates; and uncertainty around the approved depreciation rate, which TransCanada characterized as variability risk. With respect to the depreciation rate, TransCanada submitted that because of increased pipe-on-pipe competition and the maturity of the WCSB, the probability of setting the depreciation rate incorrectly is now greater than in the past.

Specific factors which TransCanada cited as increasing competitive risk since RH-4-2001 include recent open seasons on Vector and Union; a reduction in contract terms; expansion by Vector in 2002; and the increasing prospects for LNG projects in the Mainline's market areas. TransCanada submitted that LNG projects proposed for eastern Canada and the Northeast US are a new competitive threat to the Mainline, and as such, represent an increased business risk. TransCanada stated that, of the pipelines accessing the WCSB, only the Mainline faces competition from LNG directly in the markets it serves. At the same time, TransCanada expressed the view that LNG will be required to meet market demand and therefore it is advantageous for TransCanada to be involved in LNG development so it can influence where and how it enters its system. In the long term, TransCanada views it as beneficial for the Mainline to accept LNG into its system.

Position of Intervenors

CAPP submitted that the competitive issues TransCanada pointed to in this proceeding were the same as those raised in the RH-4-2001 Proceeding. These include: the swing pipeline concept and relative netbacks; alleged disadvantages related to long-term contracts on other pipelines; increasing use of short-haul transportation; potential expansion of competing pipelines; the risk that the Mainline will be unsuccessful in competing for supply; US pipelines' ability to discount; normalized versus flow-through tax treatment; and the risk that depreciation may not result in full cost recovery.

It was contended by CAPP that the Board took these factors, including the possibility of expansions of competing pipelines, into account in RH-4-2001 when it found that pipeline competition was the most significant change since RH-2-94. CAPP stated that issues associated with pipeline competition have not raised the Mainline's business risk since 2001. CAPP suggested that recent activities such as LNG and competition with Alliance and Vector are manifestations of the competitive dynamic that was already identified in RH-4-2001.

CAPP submitted that the swing pipeline argument is based on the attractiveness of the Mainline's netbacks compared with those of other pipelines, and argued that TransCanada's netback analysis is seriously flawed and unduly pessimistic. When netbacks from additional routes beyond the original six were analyzed, the Mainline's netbacks compared favourably with those of other pipelines and, for some destinations, the Mainline had the highest netbacks. For example, when the correct toll to Dawn was used, the Mainline was more competitive than routes using Alliance or Northern Border to that location.

CAPP noted that the netback study's conclusions are driven by assumptions regarding future market prices, which are inherently difficult to forecast. Different assumptions can lead to significantly different results. CAPP contended that the historical trends show the analysis to be unreliable, pointing to the difference between forecast and actual prices and the associated impact that differences in netbacks had in the rankings of the various routes, as shown in Table 4-4. For example, while TransCanada forecast that the route via the BC System and GTN to Malin would have the second highest netbacks in 2004, from January to July 2004, these netbacks were the second lowest. Further, CAPP pointed out that the differences between the netbacks from the various routes over the period to 2025 are not great. CAPP also suggested that the netback is not the only factor influencing the choice of market. In summary, CAPP submitted that the market or route that will occupy the swing position will change from time to time, as it has in the past.

It was pointed out by CAPP that the Mainline is not the only pipeline with an expiring long-term contract profile. Others include Northern Border, GTN and Northwest Pipeline.

CAPP contended that the Board has approved a number of changes since RH-4-2001, which reduce TransCanada's business risk. These include the increases in depreciation rates, the increase of the interruptible floor price to 110 percent of the firm toll, the approval of the Southwest Zone (all from RH-1-2002) and the approval of the North Bay Junction receipt and delivery point (RH-3-2004).[45] As well, TransCanada's revenue protections mitigate the business risk faced by the pipeline, including pipe-on-pipe competition, a risk which CAPP suggests has not changed since 2001.

With respect to terminal negative salvage and tax balances resulting from the flow-through methodology, CAPP noted that these factors had been raised by TransCanada as risks in previous proceedings.

CAPP argued that since TransCanada assumed that the eastern end of its system is full due to growing markets, the principal issues around competition are how much supply is available at the western end of the system and what is the risk of additional capacity being built that would draw supply from the Mainline. CAPP argued that the risk of bypass at the western end of the Mainline is not any greater than it was in RH-4-2001, since new facilities must be approved by the Board and are still subject to the economic feasibility test, which requires a demonstration of overall supply and market.

Coral had a number of concerns regarding the accuracy of TransCanada's netback study. Routes that showed the Mainline as more attractive were omitted. TransCanada used the Dawn price and the Eastern Zone toll when the applicable toll to Dawn is the lower Southwest Zone toll. Coral observed that the real market prices in the Eastern Zone are the prices at places like Parkway, Ontario, and the Iroquois and Niagara export points. Coral contended that the fact that the netbacks from the model were considerably less than the fuel cost forecasts used did not demonstrate that the Mainline is intrinsically uneconomic, but more likely indicate a problem with the model. The market price projections extending to 2025 were based on human judgments. The projections for 2005 are not consistent with current circumstances, in which the Mainline appears to be more economic and attractive to shippers than other pipeline options, including Northern Border and Alliance.

Coral argued that the Mainline's business risk is reduced because it has captive customers with inelastic demands and alternatives that are very expensive in the long run.

Ontario argued that the competitive risk from pipe-on-pipe competition, and specifically from Vector and Alliance, were dealt with by the Board in RH-4-2001 and have not materially changed since then. Ontario argued that the issue of future tax liabilities and negative net salvage have been known for a long time and do not change the Mainline's long-term business risk. Further, TransCanada has identified only two natural gas pipeline companies that are currently collecting negative net salvage in their rates. Ontario also argued that LNG has potential benefits to the Mainline as an additional source of supply and support for continued development of gas markets. Ontario stated that there was no basis to conclude that the development of LNG materially increases the business risks of the Mainline.

Like CAPP, Ontario raised the issue of enhancements to the Mainline's business risk since RH-4-2001, adding the deferral account for Repair and Overhaul Expenditures approved in

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45 National Energy Board RH-3-2004 Reasons for Decision, TransCanada PipeLines Limited (North Bay Junction Application), December 2004

RH-1-2002 to the list of changes that CAPP had outlined. Ontario argued that TransCanada had failed to give appropriate weight to these enhancements in its 2004 Tolls Application.

Referring to the netback analysis, Ontario argued that having the highest costs does not necessarily mean that a pipeline has the worst netbacks, since market prices also determine netbacks. Ontario noted that the Mainline can be competitive at times.

4.6 Operating Risk

Operating risk is the risk to the income-earning capability that arises from technical and operational factors. TransCanada submitted that operating risks have not changed materially since RH-4-2001. CAPP agreed with TransCanada in that regard.

4.7 Views of the Board

As noted in Chapter 2, there was substantial discussion as to whether, in determining the appropriate capital structure for the Mainline, the Board should consider only changes in business risk since the last assessment or use a clean slate approach. As stated there, the Board is not limited to considering evidence pertaining to significant changes since RH-4-2001. In making its assessment of business risk, the Board has considered all of the evidence presented in this proceeding, including changes in risk since 2001 and an assessment of the appropriate weights assigned to each source of risk, given currently available information.

Supply Risk

The Board notes that there was general agreement among the parties that views on supply have changed since 2001. Further, there was general agreement that TransCanada's forecast of total conventional supply presented in its Base Case was reasonable and reflective of current knowledge. Overall, the Board is of the view that reasonable reliance can be placed on the range of conventional supply estimates presented during the hearing and that significant increases in WCSB conventional supply are unlikely. As a result, the Board finds that over the longer term, the Mainline will depend, in part, on the development of unconventional or northern supply, in order to maintain throughput. This dependence is greater today than was anticipated in 2001.

Unconventional supply, such as coalbed methane and tight gas, is more uncertain given its early stage of development. Although unconventional supply is expected to at least partially offset future declines in conventional production, the extent to which and when it will do so is uncertain.

Similarly, gas from both the Mackenzie Delta and Alaska may act to offset future declines in WCSB conventional production. However, as with unconventional gas, there are uncertainties. Although TransCanada has included Mackenzie Delta gas in all of its throughput cases, it is not clear when, or if, this gas will flow, and if it does, whether it will flow on the Mainline. Therefore inclusion of Mackenzie Delta gas represents a possible downside risk for the Mainline if, in fact, these volumes do not materialize.

While the development of Alaskan supply appears more likely now than it did in 2001, commercial arrangements have not yet been negotiated. Further, if the facilities are constructed, the earliest flows would be several years away and it is not clear that these volumes would flow in whole or in part through the Mainline. In this regard, producers have sent clear signals that they want options for delivery of Alaskan gas, and utilization of the Mainline is only one of these options. The Board agrees with those parties who stated that Alaskan gas represents a possible upside for the Mainline, as shown in the Alaska-in Case, which was provided in response to an information request. Nonetheless, the Board accepts as reasonable the exclusion of Alaskan gas from the three original throughput cases.

The Board finds the ultimate potential estimates used by TransCanada in its Base, Low and High Cases, as well as its projections of WCSB production and western Canadian natural gas demand, to be reasonable. In estimating the supply available for export from western Canada to various pipelines, TransCanada made assumptions with respect to relative netback prices, pipeline utilization rates, capacity expansions and allocation methodologies. While the Board does not necessarily accept all of the assumptions used by TransCanada in this analysis, the Board finds the main three cases to be plausible. The Board also agrees with TransCanada that the Low Case is important in an assessment of business risk since it falls within the range of plausible scenarios. Further, the Board accepts that it is not solely a base case that reflects business risk and potential impact on the Mainline's earnings, but possible variations from it. In this respect, earnings are more likely to be affected in a scenario similar to the Low Case, than in more positive scenarios.

Taking into consideration changed perceptions with respect to supply since RH-4-2001 and the greater reliance on unconventional supply, the Board is of the view that there has been some increase in supply risk to which the Mainline is exposed.

Market Risk

With respect to the risk associated with the overall size of the natural gas market, the Board acknowledges that projections of natural gas demand growth in North America are lower now than at the time of the RH-4-2001 Proceeding. However, market growth is still expected to be sufficiently strong that it is not a constraint to the utilization of the Mainline.

Consequently, the Board does not consider that there has been any change associated with the Mainline's risk related to the overall size of the market. The risk associated with the market share that the Mainline is able to capture is discussed under Competitive Risk in this section.

Regulatory Risk

The regulatory context for the Mainline is evolving, but the Board finds no reason to conclude that the Mainline's regulatory risk has increased. The regulatory model continues to provide the Mainline with a reasonable opportunity to recover its prudently incurred costs. Indeed, the Board notes, as an example, that the direction from the Board in the RH-1-2002 Decision emphasizing "the importance of performing depreciation studies on a timely basis and of ensuring that depreciation rates reflect up-to-date information"[46] would indicate a directional decrease in regulatory risk. While the Board acknowledges that regulators may be unable to protect the Mainline if tolls become uncompetitive, this has always been true and does not constitute a change in regulatory risk.

The Board is of the view that the discussions between TransCanada and its stakeholders about a new business and regulatory model around the time of RH-4-2001 had not increased the regulatory risk of the Mainline, nor has the termination of those discussions reduced regulatory risk.

The Board does not accept that the Mainline's current level of regulatory risk is higher simply because, in the RH-1-2001 Decision, the Board stated that some sharing of risk between TransCanada and its shippers may be appropriate if considered on a prospective basis. The same Decision indicated that consideration of some sharing of risk between TransCanada and its shippers should take into account the appropriate balance between risk and reward and the tools required to manage such risk. The Board also notes that the statements made in the RH-1-2001 Decision were made before the commencement of the oral portion of the RH-4-2001 Proceeding.

On balance, the Board finds that there has been no measurable change in regulatory risk.

Competitive Risk

While it may have been possible in 2001 to foresee, at least in part, the manner in which competition to the Mainline would unfold, the Board is of the view that the implications of this competition are becoming clearer. Although throughput has not declined on a volume/distance basis to the same extent as billing determinants, the Board accepts that the contractual

46 RH-1-2002, *supra* note 42 at p. 43

underpinnings of the Mainline have weakened since 2001. There is also potential for LNG to capture markets in eastern Canada that were previously considered to be captive to the Mainline. As well, markets downstream of Dawn have the opportunity to acquire, and have expressed interest in acquiring, gas at Dawn. These factors could decrease reliance on the Mainline.

The Board does not find TransCanada's swing pipeline hypothesis compelling and finds the netback study to be flawed. TransCanada omitted routes that were significant in terms of volume, most notably the use of the Mainline to Niagara. This route has higher flows than the route to Iroquois, a route which was one of the six originally included by TransCanada. Of the routes provided, the use of the Mainline to Niagara offered the highest netbacks in recent history and is forecast to offer the second highest netbacks of all routes considered in TransCanada's netback study (see Table 4-4).

In response to TransCanada's assertion that the competitiveness of the Mainline relative to Alliance and Northern Border should be evaluated by comparing the netbacks from the primary destination of the pipelines, the Board notes TransCanada's contention that the Mainline competes with these pipelines in eastern Canada. Therefore, the Board is of the view that comparing these competing routes into Dawn is a relevant consideration. In this regard, the Board notes that the Mainline's netbacks from Dawn are competitive both in TransCanada's forecast and in recent history. When the Southwest Zone toll to Dawn is used, the Mainline offers better netbacks to Dawn than routes using Alliance or Northern Border. While the Board accepts that there is currently no pricing point located in the Eastern Zone that is sufficiently liquid to provide reliable pricing information, the Board notes that the use of the Dawn price combined with the Eastern Zone toll tends to underestimate the netbacks available for delivery to the Eastern Zone.

The Board is aware that forecasting market prices 20 years into the future is an inherently uncertain exercise. The Board notes that among TransCanada's original six routes, the variation between the highest and the lowest netback routes is relatively small, such that there is considerable margin for error in ranking various routes.

While it is true that the Mainline's markets are generally more distant from the WCSB than those of other ex-WCSB pipelines, netbacks are dependent upon both transportation costs and the prices obtainable in the specific markets. Therefore, the Mainline's distance to market does not necessarily mean that it will offer the lowest netbacks. Although the Mainline may at times offer the least attractive netbacks, this is not consistently the case, as shown by actual data for 2003 and for the first half of 2004. Further, the Board is of the view that the greater level of recontracting that recently occurred on the Mainline than on some other ex-WCSB export pipelines is at odds with the swing pipeline hypothesis. Consequently, TransCanada's reliance on the swing pipeline hypothesis leads the Board to conclude that TransCanada has overestimated the competitive risk facing the Mainline.

The Board accepts that the issues of negative terminal salvage, and the Mainline's deferred tax balance under the flow-through tax methodology, have the potential to affect its competitive position. The Board is of the view that the importance of such factors increases in a more competitive environment. However, the Board notes that these are not new risks. Both have been known for a considerable length of time. Further, although not determinative, TransCanada's management has played a role in taking the Mainline to the position it is in today. The Board is of the view that negative terminal salvage is not a significant competitive factor given that it is an industry-wide issue with few pipelines currently collecting negative terminal salvage in their tolls. At this time, the Board is not persuaded that negative terminal salvage and deferred tax balances suggest an increase in the business risk of the Mainline.

In response to TransCanada's contention that the Mainline has been denied tools to compete, the Board notes that previous decisions are based on the specific circumstances pertaining to those proceedings. The Board also notes that most of the examples cited by TransCanada, such as term differentiated rates and changes to contract renewal policies, predate increased competition. An examination of Board Decisions since the level of competition has increased, in fact, shows that the Board has been responsive in making changes when circumstances warrant and in approving tools to compete. Examples of this include the increase in the Mainline's depreciation rate, the increase in the interruptible transportation floor price, the approval of the Southwest Zone, and the approval of the North Bay Junction receipt and delivery point.

Taking into consideration the further deterioration in the contractual underpinnings of the Mainline, the market interest in acquiring natural gas supply at Dawn and the prospects for LNG in the Mainline's market areas, the Board finds that, on balance, the Mainline's competitive risk has increased since RH-4-2001, although not to the extent suggested by TransCanada.

Operating Risk

The Board accepts the views of both TransCanada and CAPP that operating risks have not changed materially since RH-4-2001.

Depreciation and Business Risk

There was discussion during the hearing regarding the extent to which regularly adjusting depreciation rates to reflect current best estimates of economic life affects the risk faced by TransCanada.

The Board is of the view that there are two distinct aspects to risk as it relates to business risk and depreciation rates. The first is that the current best estimate of economic life, which is reflected in the depreciation rates, may ultimately prove to be wrong. Various business factors, including changes to supply or competitive forces, could alter the economic life of the Mainline. This possibility cannot be fully mitigated and therefore should be compensated through cost of capital.

The second aspect of depreciation-related risk is that the depreciation rates in use may not actually reflect the estimates of economic life that would be selected if assessed at that point in time. A company can mitigate the risk that the estimates in use are not current by bringing forward an application to reconsider its depreciation rates. The part of this risk that is mitigable should not be compensated through the cost of capital. Should it become apparent that depreciation rates do not adequately reflect current estimates of economic life, it is incumbent on the management of the company to seek to change depreciation rates, not to expect incremental compensation through the cost of capital.

Still related to the second aspect, there is a potential that a company's tolls may not incorporate sufficiently high depreciation rates because competitive factors would prevent such rates from being charged. This potential, if significant, is appropriately compensated through the cost of capital.

The assessment of cost of capital should assume that the depreciation rates reflect the best assessment of economic life of the pipeline. Consequently, resetting depreciation rates to reflect a new best estimate of economic life does not, by itself, reduce business risk from what it would be absent a change in the best estimate.

With respect to the argument that as rate base declines, business risk is reduced, the Board agrees that the total level of Mainline capital at risk decreases over time as the system is depreciated. The Board also accepts that there would be no capital recovery risk remaining should the system be fully depreciated. However, the Board is of the view that the business risk of the remaining assets does not decline simply because the rate base is becoming smaller.

In summary, in relation to the aspects of risk that cannot be mitigated, the Board does not consider that the changes in the Mainline's depreciation rates that were approved in RH-1-2002, in and of themselves, reduced the Mainline's business risk; the changes merely re-based the Mainline's depreciation rates to reflect current knowledge concerning economic life. The Board is of the view that there has been no change to the risk that the current best estimate of the economic life may ultimately prove to be wrong.

Overall Business Risk

The Board finds that, overall, the business risk to which the Mainline is exposed has increased since RH-4-2001, as a result of increases in supply risk and competitive risk.

Chapter 5

Comparable Investments

5.1 After-Tax Weighted-Average Cost of Capital Evidence

A company's ATWACC is the after-tax weighted-average cost of each source of capital included in its capital structure. It is also referred to as the Weighted-Average Cost of Capital (WACC) and is regularly used in capital budgeting as a discount rate for net present value analysis and the hurdle rate for internal rate of return analysis. Throughout the hearing, TransCanada also referred to ATWACC as the overall cost of capital and overall return on capital.

Position of TransCanada

TransCanada sponsored the evidence of Drs. Kolbe and Vilbert who used an ATWACC-based approach to estimate the cost of capital and appropriate deemed equity ratio for the Mainline. This evidence relied on estimated ATWACCs for two sample groups of companies, considered to be of similar risk to the Mainline. The specific approach used by Drs. Kolbe and Vilbert (K&V ATWACC Methodology) is described below.

After considering the views of its experts, TransCanada chose to apply for a deemed equity ratio of 40 percent, which, when combined with the RH-2-94 Formula ROE of 9.56 percent and an after-tax market cost of debt of 4.14 percent, results in an ATWACC of 6.3 percent. TransCanada expressed the view that an ATWACC of 6.3 percent would improve the relative financial position of the Mainline but that it would fall short of meeting the fair return standard, adding that an ATWACC of 6.9 percent would be more representative of a fair return. Assuming an ROE of 9.56 percent, an ATWACC of 6.9 percent implies a common equity ratio of approximately 51 percent.

Description and Justification for the K&V ATWACC Methodology

The K&V ATWACC Methodology is based on the premise that a sample of companies with levels of risk similar to the subject company should have a comparable overall cost of capital. Under this methodology, an appropriate group of sample companies is established and their average market-value capital structures over a specific time period is estimated. Then, each of the sample companies' cost of equity (ROE) and after-tax market cost of debt is estimated. These cost estimates are then combined with each company's capital structure to determine its ATWACC and subsequently, the average ATWACC of the sample. Finally, the equity ratio that results from holding the sample's average ATWACC constant, but substituting the Mainline's ROE, is calculated. A comparison between the Mainline and the sample's average implied equity ratio is made. As set out in more detail below, this was undertaken for two sample groups.

Drs. Kolbe and Vilbert submitted that it is the overall cost of capital that should be used to determine a fair overall rate of return to meet the fair return standard. Dr. Kolbe emphasized that the cost of equity varies not just with business risk, but also with financial risk, which in turn depends on the equity ratio. He acknowledged that the use of the K&V ATWACC Methodology as a regulatory approach is not under consideration in this application, as it was in RH-4-2001. However, Dr. Kolbe submitted that the Board cannot accurately interpret capital market risk-return evidence concerning the deemed equity ratio unless the interaction between the cost of equity and the capital structure is taken into account. In this context, Dr. Kolbe submitted that, if applied properly, the K&V ATWACC Methodology and the Board's traditional methodology of establishing an ROE and a deemed equity ratio should yield the same results.

It was suggested by Drs. Kolbe and Vilbert that there are multiple minimum-cost capital structures. They noted that interest expense from debt is tax deductible, but submitted that as a corporation takes on more debt, there are non-tax effects of debt that offset the tax benefits. These non-tax effects include a loss of management flexibility, the possibility of sending negative signals to investors, and costs and risks associated with financial distress. Dr. Kolbe expressed the view that both the research and empirical evidence indicate that there is no well-defined optimal capital structure within an industry and the range of capital structures over which the value of a firm in any industry is maximized is wide and should be treated as flat (that is, the ATWACC curve is flat over a broad middle range of capital structures).

Drs. Kolbe and Vilbert recommended that, in the future, the Board analyze the trade-off between capital structure and cost of equity explicitly and quantitatively rather than only subjectively and qualitatively.

Estimates of ATWACC and Implied Common Equity Ratios

As discussed above, the first step of Dr. Vilbert's analysis was to select two groups of sample companies and determine their average market-value capital structure. Since no companies involved exclusively in long-haul gas transmission exist in Canada or the US, Dr. Vilbert used a sample of Canadian Utilities and a sample of US gas local distribution companies (LDCs). Dr. Vilbert applied a series of screens intended to create samples whose primary business is as a regulated utility with business risk generally similar to the Mainline.

Then, for each sample, Canadian capital market data were used to estimate each of the sample companies' ROE and after-tax cost of debt. These cost estimates were then combined with each company's market-value capital structure to determine its ATWACC and the average ATWACC of the sample. Holding the sample ATWACC constant, Dr. Vilbert substituted the Mainline's ROE to calculate the implied equity ratio.

Drs. Kolbe and Vilbert submitted that the Canadian Utilities sample is an obvious benchmark group but noted that this group does not include many gas pipelines. Dr. Kolbe expressed the view that the general increase in competition for North American regulated industries and increased uncertainty due to the events of 11 September 2001 would tend to make current ATWACC estimates understate the true risk the sample companies face today. As well, he submitted that the Canadian gas LDCs, which are part of the Canadian Utilities sample, tend to be exposed to more short-term risk than the Mainline. However, he concluded that the overall Canadian Utilities sample is exposed to less long-term risk than the Mainline.

Dr. Kolbe submitted that the Mainline's overall cost of capital should be above that of the US gas LDCs sample. He contended that the Mainline has more long-term risk, although less short-term risk, than the US gas LDCs on average.

The estimated ATWACCs and implied common equity ratios at an ROE of 9.56 percent are summarized in Table 5-1. Dr. Vilbert estimated a deemed equity ratio range of 40 to 50 percent for his Canadian utilities sample (with a midpoint of 45 percent) and of 45 to 55 percent (with a midpoint of 50 percent) for his US gas LDCs sample. Dr. Kolbe submitted that TransCanada's requested deemed equity ratio of 40 percent was below what he would have recommended, which was in the range of 45 percent to 55 percent.

Dr. Vilbert presented a number of sensitivities in which he relaxed various assumptions, one at a time. These sensitivities included: using book-values weight; using a regression period ending October 2003; using different estimates of risk-free rates; using traditional single-factor beta regressions; removing the Merrill Lynch adjustment; using different estimates of Market Risk Premium (MRP); using a different cost of debt; and estimating the sample capital structure over the period ending May 2000. The outcomes of selected sensitivities are presented in Table 5-1. Dr. Vilbert contended that none of the sensitivities represent the best available estimate of the cost of capital for the Mainline.

Assumptions and Parameters

The following provides further details on the key assumptions and parameters employed by Drs. Kolbe and Vilbert in their estimation of each sample company's ATWACC.

Estimation of the Rate of Return on Equity

The estimated ROE of each sample company was an input in the estimation of its ATWACC. When estimating the market determined ROE for each of the sample companies, Dr. Vilbert used a risk positioning analysis, which is also known as Equity Risk Premium (ERP) analysis, and a Discounted Cash Flow (DCF) analysis. Dr. Vilbert expressed the view that, for both samples, the results of the DCF analysis are more variable and less reliable than those based upon the ERP analysis. He provided the results of the DCF analysis as a check on the results of the ERP analysis because it is a method that has been extensively used in the past. Dr. Vilbert also submitted that short-term risk-free rates have been driven below their historical averages. Therefore, Dr. Vilbert primarily relied on the results from the long-term ERP analysis in the determination of each of the sample companies' ROE.

Table 5-1
Estimated ATWACCs and Implied Equity Ratios

	ERP[1] Short-Term Rates				ERP Long-Term Rates			DCF[2]	
	CAPM[3]	ECAPM[4]			CAPM	ECAPM		Simple	Multi-Stage
		1%	2%	3%		1%	2%		
Dr. Vilbert's Original Estimates									
Canadian Utilities Sample									
ATWACC	5.6	5.8	6.0	6.2	6.4	6.6	6.8	7.2	6.6
Equity Ratio at 9.56% ROE	26.8	30.4	33.9	37.4	41.8	45.3	48.8	57.2	44.7
US Gas LDCs Sample									
ATWACC	5.5	5.8	6.1	6.4	6.6	6.9	7.2	7.8	7.8
Equity Ratio at 9.56% ROE	25.9	31.2	36.6	41.9	45.2	50.5	55.9	67.2	67.1
Dr. Vilbert's Sensitivity Analysis Estimates									
Canadian Utilities Sample									
Using Book-Value rather than Market-Value Weights									
ATWACC	5.2	5.3	5.5	5.6	5.8	5.9	6.1		
Equity Ratio at 9.56% ROE	19.6	22.2	24.7	27.3	30.5	33.0	35.6		
Using Short-term interest rate of 2.9% and long-term interest rate of 5.35% (rather than 3.3% and 5.6% respectively)									
ATWACC	5.4	5.6	5.8	6.0	6.3	6.5	6.7		
Equity Ratio at 9.56% ROE	23.3	26.9	30.4	33.9	39.6	43.1	46.6		
Using unadjusted betas									
ATWACC	5.0	5.3	5.5	5.8	5.9	6.2	6.5		
Equity Ratio at 9.56% ROE	15.4	20.7	26.0	31.2	32.1	37.4	42.7		
Using short-term MRP[5] of 6.0% and long-term MRP of 5.0% (rather than 6.5% and 5.5% respectively)									
ATWACC	5.5	5.6	5.8	6.0	6.3	6.5	6.6		
Equity Ratio at 9.56% ROE	24.2	27.7	31.3	34.8	39.2	42.7	46.2		
Using 6.2% cost of debt (rather than 6.37 %)									
ATWACC	5.5	5.7	5.9	6.1	6.4	6.6	6.7		
Equity Ratio at 9.56% ROE	27.5	30.9	34.4	37.8	42.1	45.6	49.0		
Using Market-value capital structures estimated over the 60-month period ending May 2000									
ATWACC	5.5	5.7	5.9	6.1	6.3	6.5	6.7		
Equity Ratio at 9.56% ROE	25.3	28.7	32.1	35.5	39.6	43.0	46.4		
US Gas LDCs Sample									
Using Book-Value rather than Market-Value Weights									
ATWACC	5.2	5.5	5.7	5.9	6.1	6.3	6.5		
Equity Ratio at 9.56% ROE	20.1	24.4	28.6	32.9	35.4	39.7	44.0		

1 Equity Risk Premium
2 Discounted Cash Flow
3 Capital Asset Pricing Model
4 Empirical Capital Asset Pricing Model
5 Market Risk Premium

Equity Risk Premium Analysis

Under the ERP analysis, the cost of equity is estimated as the sum of a current risk-free interest rate (risk-free rate) and a risk premium. The risk premium is the amount of compensation that an investor requires over the risk-free rate in order to be compensated for the additional levels of risk associated with a specific security. The most common ERP model is the Capital Asset Pricing Model (CAPM), under which a security's risk premium is the product of an MRP and the security's beta. In the CAPM model, the risk-free rate and MRP are common to all securities and the variation in the ROEs of various securities is solely dependent on each security's beta. Beta is a measure of the systematic risk of a security. It measures the extent to which a stock price fluctuates relative to fluctuations in the market benchmark.

Dr. Vilbert also relied on a second ERP-based model, which is the Empirical Capital Asset Pricing Model (ECAPM). Dr. Vilbert submitted that empirical research has demonstrated that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta and that the use of an ECAPM approach can reduce this overstatement. For the short-term benchmark version of his ECAPM ERP analysis, Dr. Vilbert used adjustment coefficients of 1, 2, and 3 percent. For the long-term benchmark version of his ECAPM ERP analysis, Dr. Vilbert used adjustment coefficients of 1 and 2 percent.

Dr. Vilbert estimated two versions of the ERP analysis based on a benchmark short-term risk-free rate and a benchmark long-term risk-free rate. His short-term benchmark version used a short-term risk-free rate of 3.30 percent and a short-term MRP of 6.5 percent. His long-term benchmark version used a long-term risk-free rate of 5.60 percent and a long-term MRP of 5.5 percent.

For the Canadian Utilities sample, Dr. Vilbert calculated betas using a two-factor model, in which betas are calculated from a regression that includes both the excess returns on the S&P/TSX Index (S&P/TSX) and the excess returns on a pure Government bond factor. Dr. Vilbert stated that the two-factor model adjusts, in part, for the extra sensitivity to interest rate changes of the returns of companies regulated on the basis of original cost rate base. He then adjusted the estimated betas according to the Merrill Lynch adjustment procedure to compensate partially for sensitivity to interest rate changes of companies regulated on the basis of original cost rate base.

Dr. Vilbert estimated the betas of the firms in the Canadian Utilities sample over a five-year period ending May 2000. Dr. Vilbert chose this time period due to the significant decline in the statistical relationship between the market return as measured by S&P/TSX and the companies' returns during the most recent five years. Drs. Kolbe and Vilbert acknowledged that there is not a match between the time period over which their capital structure and beta calculations were made, but submitted that this explicit violation would underestimate to a lesser extent the ATWACC of the Canadian Utilities sample than the use of more recent betas. They noted that very low or even negative betas would result if the most recent five years had been used.

For the US gas LDCs sample, Dr. Vilbert used betas estimated by *Value Line* for the most recent five-year period. Since the betas reported by *Value Line* are adjusted, he reversed the adjustment process to obtain unadjusted values. This was done because the US LDCs did not exhibit the statistically significant degree of interest rate sensitivity that the Canadian utilities did.

Discounted Cash Flow Analysis

Dr. Vilbert provided estimates of the cost of equity for each of the sample companies based on the DCF analysis. He expressed the view that DCF analysis is conceptually sound if its assumptions are met but can run into difficulty in practice because those assumptions are so strong and hence, so unlikely to correspond to reality. Dr. Vilbert expressed the view that the DCF model's strong assumptions make the DCF analysis inherently less reliable than the ERP analysis.

Estimation of the After-Tax Cost of Debt and Cost of Preferred Equity

Dr. Vilbert estimated the October 2003 yield on 'A' rated utility bonds to be 6.37 percent. Combined with the Mainline's estimated marginal income tax rate for 2004 of 34.99 percent, he arrived at a 4.14 percent after-tax market cost of debt for 'A' rated utilities. Dr. Vilbert set the cost of preferred equity equal to the after-tax market cost of debt. The same cost of debt and preferred equity was used for 'A' rated utilities for both samples.

Estimation of the Capital Structure

The capital structure for each sample company in the ERP analysis was estimated by using the market value of common equity, preferred equity and debt from the most recent five years of publicly available data. For the DCF analysis, the most recently reported market-value capital structures were used. Dr. Kolbe expressed the view that it would contradict economic theory to use book-value weights for the companies' capital structures. He submitted that the true beta depends on the market value of the firm's capital structure for both regulated firms and for unregulated firms. Thus, the measured beta of a regulated company sample will be lower when its market-to-book ratio is above one than when its market-to-book ratio equals one. Dr. Kolbe contended that with a market-to-book ratio over one, use of book-value weights can lead to a serious understatement of the company's true required ROE.

TransCanada's Response to CAPP's Evidence

In response to Dr. Booth's assertion (see Position of Intervenors below) that regulators fail when a regulated company does not display a particular market-to-book ratio, Dr. Kolbe submitted that regulators have no control over market values. Dr. Kolbe submitted that underlying Dr. Booth's evidence on the meaning of the market-to-book ratio is a simple model of stock price formation. He contended that if that model were valid, the implied true ROE of rate-regulated investments would be far too low, and in most cases lower than the benchmark 30-year Government bond interest rate used in the Board's RH-2-94 Formula. Dr. Kolbe submitted that the market-to-book ratio is not a reliable test of whether the returns on rate-regulated investments are reasonable. TransCanada's evidence showed that its market-to-book ratio was 1.98 as at the second quarter of 2003.

Position of Intervenors

CAPP expressed the view that an ATWACC-based methodology relies on an inextricable link between the ROE and capital structure. CAPP submitted that it is not possible for the Board to consider an ATWACC-based methodology because it would require consideration of the cost of equity, which is not an issue in this proceeding. For the same reason, CAPP did not present evidence concerning estimation of the cost of equity capital. CAPP argued that the ATWACC evidence presented in this hearing has the same problems that the Board discussed in the RH-4-2001 Decision.

CAPP sponsored the evidence of Dr. Booth, who indicated that it is a fundamental contradiction to use an ATWACC-based methodology in regulatory filings as it is a mirror image of shareholder value maximization. Dr. Booth recommended that the Board ignore this indirect approach and continue with the traditional methodology. Dr. Booth contended that book values rather than market values should be utilized in the determination of the Mainline's ROE. He stated that the market, not the Board, determines market values. From Dr. Booth's perspective, fair and reasonable rates imply that the regulated firm's market-to-book ratio should be around one. He expressed the view that accepting market-value weights significantly different from book-value weights would imply that regulation has failed.

IGUA submitted that the equity component of ATWACC is no more reliable as a regulatory tool, than ATWACC itself; that it was subject to all the flaws of ATWACC and should be rejected.

Coral expressed the view that the ATWACC analysis is fundamentally flawed by its reliance on market-value capital structures and that the comparative return analysis is meaningless as an indicator of the cost of capital. Coral submitted that for a regulated utility, whose earnings are a direct function of the book value of its assets, the market-to-book ratio is valuable in determining whether the utility is earning its cost of capital.

Ontario expressed the view that the ATWACC analysis is flawed and unreliable. Ontario submitted that the Board should give no weight to the deemed equity range expressed by Drs. Kolbe and Vilbert for the Mainline. Ontario highlighted several statements in Dr. Kolbe's written evidence in support of the view that financial theory on minimum-cost capital structure has deficiencies and shortcomings. Ontario also submitted that the analysis of Drs. Kolbe and Vilbert had insufficient data from companies exclusively involved in natural gas transmission.

Views of the Board

The Board accepts that ATWACC-based methodologies have theoretical merit, but is of the view that a number of empirical concerns limit their usefulness as a tool to assess cost of capital or the Mainline's appropriate deemed equity ratio.

The Board is cognizant of the fact that there are no companies involved exclusively in long-distance natural gas transmission, and the approach must therefore rely on sample companies that are not directly comparable. While the sample of Canadian Utilities is an obvious benchmark, the

Board notes that all firms in Dr. Vilbert's Canadian Utilities sample derive a portion of their revenues from unregulated activities. Since these activities are typically riskier than gas pipeline operations, the estimated cost of capital for these firms tends to overstate the cost of capital of their regulated operations, and indirectly that of the Mainline. In the Board's view, the evidence of Drs. Kolbe and Vilbert did not adequately address this concern.

The Board notes that the K&V ATWACC Methodology assumes a specific relationship between a company's ROE and capital structure through the reliance on the assumption that there is a broad range over which the ATWACC curve is flat. The Board has acknowledged in previous decisions that there is a relationship between ROE and capital structure, but has traditionally addressed this relationship qualitatively, rather than quantitatively.

The Board accepts that, over a certain range, the ATWACC curve may be flat or virtually flat. However, in the Board's view, the evidence does not persuasively demonstrate the breadth of this range. Therefore, the Board is of the view that caution should be applied in relying on ATWACC-based evidence from companies with capital structures significantly different from that which is deemed for the Mainline. In this regard, the Board notes that the average estimated level of common equity for the companies in the US gas LDCs sample differs significantly from the currently deemed ratio for the Mainline. Further, it also exceeds that estimated for most companies in the Canadian Utilities sample. In the Board's view, these differences in capitalization are likely reflective of material differences in business risk. Consequently, the Board places little reliance on the US gas LDCs sample, or on firms in the Canadian Utilities sample that exhibit significantly different equity ratios.

In addition, the Board notes that during the ATWACC estimation process, numerous adjustments were made, all of which result in an increase to the estimated ATWACC. As can be observed in Table 5-1, the impact of relaxing even a single assumption can be significant.

The Board has particular concerns with the inconsistent time periods over which the Canadian Utilities sample's betas were derived (five-year period ending May 2000) and the corresponding market-value capital structures were estimated (five-year period ending October 2003). The Board notes that Drs. Kolbe and Vilbert emphasized the importance of the fundamental relationship between a firm's true beta and market value capital structure. The Board is of the view that this empirical inconsistency weakens the application of the K&V ATWACC Methodology.

In the context of this application and evidence, the Board is of the view that due to the numerous adjustments and time period inconsistency of the estimation process, the K&V ATWACC Methodology does not yield cost of capital estimates that are determinative of an appropriate deemed equity ratio for the Mainline. While the Board accepts that the ATWACC-based evidence of Drs. Kolbe and Vilbert directionally supports an increase to the Mainline's common equity ratio, the evidence provides little insight on the appropriate magnitude of such an increase.

With respect to concerns expressed over market-to-book ratios, the Board does not expect regulated utilities to display a particular market-to-book ratio and recognizes that many different market forces can influence a company's market-to-book ratio. At the same time, the Board is of the view that market-to-book ratios are an indication of a company's financial health. The Board recognizes that TransCanada's market-to-book ratio reflects that of the consolidated entity, not that of the Mainline or of TransCanada's Canadian pipeline operations. Nonetheless, given that the majority of TransCanada's income comes from its Canadian regulated operations, while not determinative, the Board is of the view that TransCanada's market-to-book ratio of approximately two provides some indication that the current deemed equity ratio of the Mainline cannot be considerably below the appropriate level.

5.2 Other Comparable Investments

5.2.1 Comparisons to Alliance, M&NP, Enbridge and Westcoast

Position of TransCanada

TransCanada expressed the view that it should earn returns at least comparable to Alliance, Maritimes & Northeast Pipeline (M&NP) and Enbridge Pipelines Inc. (Enbridge) since it viewed all of these pipelines as being of lower risk than, although of comparable risk to, the Mainline. According to TransCanada, the returns of Alliance and M&NP provide real-world data demonstrating the level of return necessary to promote investment in pipeline infrastructure and are the best examples of investments of comparable risk to the Mainline. These pipelines also provide evidence of the returns necessary to meet the capital attraction standard. TransCanada submitted that the most meaningful comparators of alternative investments are the other pipelines that are regulated by the Board.

TransCanada noted that the Board said in its RH-4-2001 Decision that:

> The Board does not consider the evidence pertaining to comparisons of the Mainline with Alliance, M&NP and Enbridge to be particularly meaningful in establishing a fair return for the Mainline. The Board notes that TransCanada's evidence on relative business risk only considered certain factors and ignored several others. More importantly, the returns achieved by these pipelines reflect a different risk-reward environment and different circumstances. A more meaningful comparison would require a thorough assessment of the relative business risks of each pipeline as well as an

estimation of what each pipeline's cost of capital might be absent differences in circumstances.[47]

TransCanada submitted that it tried to address the Board's concerns discussed in the RH-4-2001 Decision and attempted to provide a more thorough assessment of the relative business risks of these pipelines and the Mainline based on publicly available data.

As noted in Chapter 2, TransCanada discussed three methodologies for comparing the total return of pipelines: ATWACC, total equity return and return on rate base, which is based on an after-tax ROE, and before-tax embedded cost of debt. The third methodology was only used to compare TransCanada's overall return on rate base of approximately 9.0 percent with 33 percent equity, or 9.1 percent with 40 percent equity, with the awards of the US Federal Energy Regulatory Commission (FERC), which have averaged 10.0 percent to 10.5 percent since 2002, when calculated on the same basis.

Table 5-2 compares the ATWACC for Enbridge, M&NP, Alliance and Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission Canada (Westcoast), based on data provided by TransCanada.

Table 5-2
Cost of Capital Information

	Equity Ratio (percent)	**Approved ROE** (percent)	**ATWACC**[1] (percent)
Mainline (at 40% equity)	40	9.56	6.3
Mainline (at 33% equity)	33	9.56	5.9
Enbridge[2]	45	13.0	8.1
M&NP	25	13.0	6.4
Alliance	30	11.3	6.3
Westcoast	31	9.56	5.8

1 The after-tax market cost of debt used by TransCanada to calculate the ATWACC was 4.14 percent for an 'A' rated utility.

2 As estimated by TransCanada.

The following discussion of comparisons to Alliance, M&NP, Enbridge and Westcoast also pertains to the Relative Business Risk of Pipelines analysis presented in Section 5.2.2 and the Comparative Investment analysis presented in Section 5.2.3 and will not be repeated in those sections.

Alliance

TransCanada stated that all aspects of the business risk of Alliance are similar to or lower than those of the Mainline, primarily because Alliance was supported by 15-year transportation

47 RH-4-2001, *supra* note 4 at p. 35

contracts at the time the pipeline commenced operation. Further, TransCanada submitted that Alliance's five-year renewal provisions, with accelerated depreciation in the last five years of the contracts if they are not renewed, serve to lower Alliance's business risk. As a result of having longer contract terms, TransCanada contended that Alliance has less exposure to competitive, market, regulatory and supply risks. TransCanada claimed that Alliance's supply and market risks are also reduced relative to the Mainline because Alliance offers higher netbacks than the Mainline.

TransCanada suggested that Alliance benefits from a higher overall depreciation rate and therefore a shorter depreciation period. TransCanada acknowledged that Alliance faces shipper default risk but viewed it as insignificant given the apparent creditworthiness of its firm shippers and its ability to require financial assurances from its shippers.

With respect to Alliance's construction cost risk, TransCanada argued that this was a mitigable risk and therefore should not receive compensation in the return. Further, those risks were borne and realized in the past. Since present return is not to compensate a utility for risks borne and realized already, TransCanada argued that the construction cost risk is irrelevant. It also noted that Alliance's lower return applied to actual capital costs so that Alliance's total return in dollars increased as a result of the construction cost overruns.

M&NP

TransCanada viewed the overall business risk of M&NP as lower than the Mainline, primarily due to its long-term contracts. It noted that when M&NP was approved, it was viewed as having the same business risk as other Group 1 pipelines, but that was prior to the approval of Alliance and Vector. TransCanada suggested that the supply risk which M&NP bears due to accessing a new supply basin is fully mitigated by the existence of 20-year backstop agreements with Mobil Canada Products Ltd. and Mobil Properties Ltd. so that M&NP has less supply risk than the Mainline.

According to TransCanada, M&NP's regulatory risk is less than the Mainline's because there is less risk of competing pipelines and because its return was set for a five-year period and was subsequently extended for two years. TransCanada submitted that M&NP's higher market risk is offset by the existence of long-term contracts. TransCanada further noted that depreciation rates are higher than for the Mainline.

Enbridge

While the Enbridge mainline operates with month-to-month nominations, TransCanada submitted that the impact of revenue variations is mitigated in the short term by the Transportation Revenue Variance provisions in the settlements Enbridge negotiated with its shippers between 1995 and 2004. TransCanada claimed that Enbridge's Transportation Revenue Variance offers greater revenue assurance than its own deferral accounts due to its automatic nature.

TransCanada noted that Enbridge's supply risk is reduced by the expectation of growing oil production but increased by exposure to the various environmental, economic, consultative and jurisdictional risks that impact new and expanded oil sands projects. It added that Enbridge also faces increasing pipe-on-pipe competition from Trans Mountain Pipe Line Company Ltd. and Express Pipeline Ltd.

Westcoast

TransCanada initially excluded Westcoast from its analysis of comparable investments and its comparative risk analysis but provided information in response to information requests. TransCanada expressed the view that the inclusion of Westcoast in this analysis would be circular since Westcoast's ROE is derived using the RH-2-94 Formula. TransCanada's position was that the inclusion of Westcoast, or any other company on the RH-2-94 Formula, would only lead to the conclusion that pipelines using similar methodologies tend to have similar returns. TransCanada also indicated that Westcoast was not a relevant comparator because its return was too low.

TransCanada contended that, although Westcoast agreed to the RH-2-94 Formula ROE on an equity thickness of 31 percent in its negotiated settlement for 2004 and 2005, it was because Westcoast's return was part of an overall settlement reflecting the best interests of the corporation, rather than being reflective of a fair return.

Position of Intervenors

CAPP

CAPP submitted that TransCanada's comparisons to Alliance, M&NP and Enbridge are inappropriate and should be given little weight. CAPP submitted that the comparisons to M&NP and Alliance primarily support a request for an increase in ROE, not equity thickness.

It was noted by CAPP that Alliance took risks that the Mainline does not face, including: incurring some capacity risk through a marketing affiliate; credit risk when shippers default, which has happened; interest rate risk with the return on equity locked in for 15 years; risk associated with locking in the depreciation rate for the long term; and construction risk, which was realized and reduced Alliance's ROE from 12 percent to 11.25 percent. While Alliance's lower return resulting from construction cost overruns was applied to the resulting larger rate base, the Mainline has had many cost overruns with no rate of return impairment.

Further, CAPP pointed out that Alliance's return on equity of 12 percent (before being reduced because of cost overruns under the construction risk incentive) was negotiated in 1996 when the return on equity resulting from the RH-2-94 Formula was 11.25 percent. It was filed with the Board when the RH-2-94 Formula ROE was 10.67 percent. CAPP noted that Alliance, at 30 percent, has a lower equity ratio than the Mainline.

CAPP submitted that at the time the capital structure was established, there were differences associated with M&NP that justified the higher return, including the requirement to access supply from a few fields with untested reserves. CAPP also pointed out that M&NP has 25 percent equity in its capital structure.

It was observed by CAPP that since 1995, Enbridge's return has been negotiated as part of an incentive agreement and the returns on equity cannot be looked at outside this context. Further, Enbridge's higher equity ratio reflects common carriage of an oil pipeline and related characteristics such as tolls designed on the basis of forecasts without deferral accounts.

CAPP viewed the Mainline as being of lower or similar risk to Westcoast and submitted that Westcoast's 31 percent common equity ratio was a valid benchmark.

Coral

Coral argued that both Alliance and M&NP fixed their allowed returns for an extended period at a level that reflected long-term bond yields at the time. Their return on equity included compensation for assuming the risk of locking in the rate. Since then, these pipelines have benefited because interest rates have dropped significantly. Consequently, the return on equity for these two pipelines is not comparable to the Mainline.

From Coral's perspective, in order to make them comparable, one should remove the premium for fixing the return on equity for the term of the agreement and adjust for changes in interest rates since that time. Coral described Alliance's ROE of 12 percent as 75 basis points above the RH-2-94 Formula return on equity at the time is was negotiated and 133 basis points above the RH-2-94 Formula ROE at the time the application was filed with the Board. Coral submitted that in the case of M&NP, evidence was filed, and accepted by the Board, which indicated that the ROE included a 75 to 100 basis points premium for locking in return on equity for five years.

When asked by Coral to adjust for a locking-in premium and changes in interest rates, TransCanada calculated the ATWACCs of Alliance and M&NP as 5.9 percent, the same as the Mainline at a 33 percent equity thickness. Coral further noted that, at the time Alliance set its ROE, it was only 75 basis points above the RH-2-94 Formula ROE, rather than the 133 basis points used in the above calculations. Using a 75 basis points differential would result in an adjusted ATWACC below 5.9 percent.

With respect to TransCanada's assertion that M&NP's regulatory risks are less than the Mainline's because the return on equity was set for five years and subsequently extended, Coral argued that Group 1 pipelines regulated by the Board do not have materially different regulatory risks simply because they are able to successfully negotiate rate of return with their shippers.

Coral noted that the Board last addressed Enbridge's equity component in RH-2-94. Since then Enbridge has been successful in negotiating settlements with its shippers. Coral submitted that Enbridge's success with its shippers does not reveal anything about the Mainline's cost of capital.

Ontario

Ontario argued that the Mainline and Westcoast have similar overall business risk, including access to WCSB supply, competition from new pipeline takeaway capacity, excess pipeline capacity and an increase in the number of shippers holding short-term contracts. In addition, Westcoast faces similar issues with respect to competition with US pipelines and concerns of the credit rating agencies. Ontario contended that since there is no material difference in business risk between Westcoast and the Mainline, both rely on the RH-2-94 Formula and Westcoast has settled on a deemed equity level of 31 percent for 2004 and 2005, there is no reasonable basis for increasing the Mainline's deemed equity thickness above 33 percent.

Ontario argued that TransCanada's lower risk ranking for Enbridge was without merit given the nature of the risks that this pipeline faces.

5.2.2 Relative Business Risk Analysis

Position of TransCanada

The Mainline was compared with a selected group of nine pipelines: three Canadian pipelines that are not subject to the RH-2-94 Formula (Alliance, M&NP and Enbridge); five pipelines in which TransCanada has an ownership interest (Northern Border, GLGT, GTN, Iroquois and Portland Natural Gas Transmission System (PNGTS)); and Vector.

To prepare the analysis, TransCanada rated each pipeline in five major risk categories, three short-term and two long-term, based upon its assessment of publicly available information. The weights applied to each category are shown in Table 5-3.

TransCanada defined short-term risk as one that affects variability of earnings year over year. For pipelines operating under a fixed forward test year methodology, the short term was defined as one year, whereas for pipelines operating under multi-year settlements, the short term was equivalent to the term of the settlement, regardless of its length. Everything beyond these periods was considered to be long term in this analysis. TransCanada stated that in the short term, the fundamental risk is that the achieved return will fall short of the expected return, but in the long term, the fundamental risk is that the utility will become uneconomic, resulting in a loss of all or part of the capital that has been invested. TransCanada also referred to the potential for the premature truncation of capital recovery as truncation risk. TransCanada assigned 75 percent weighting to the long-term risks and 25 percent weighting to what it considered to be the less significant short-term risks.

For each category of risk and for each pipeline, TransCanada assigned a risk ranking between zero and four and then calculated a total risk ranking for the pipeline given the weights selected. The resulting Business Risk Index for each pipeline was compared graphically and in tabular form with approved returns on capital (ATWACC). The tabular comparison is set out in Table 5-3. TransCanada argued that it is not appropriate to compare pipelines based on equity thickness alone since many pipelines have risk reflected in their return on equity rather than entirely in equity thickness. One component of TransCanada's ranking of long-term revenue and cost risk was its assessment of relative netbacks and its view of the Mainline as the swing pipeline (see Section 4.5, Competitive Risk).

TransCanada concluded from this analysis that there is a positive correlation between business risk and returns but that the Mainline has the highest business risk ranking and the lowest approved return on capital of the pipelines selected. Even if long-term risk was weighted at 50 percent, TransCanada contended that the analysis would still support a 40 percent equity thickness for the Mainline. A 25 percent long-term weighting would still show the Mainline's return as low relative to Alliance and M&NP.

Table 5-3
TransCanada's Comparison of Business Risk Index to the Approved Return on Capital

	Short-term Risks				Long-term Risks		Business Risk Index	ATWACC
	Revenue	Cost	Operating	Regulatory	Revenue and Cost	Operating		
Weights	15%	5%	5%	0%	70%	5%	100%	(%)
Mainline (40%)	0	1	0	1	4	1	**2.90**	**6.3**
Mainline (33% in 2003)	0	1	0	1	4	1	**2.90**	**6.0**
GLGT	3	4	1	1	3	1	**2.85**	**8.2**
Vector	3	2	1	1	3	1	**2.75**	**7.1**
PNGTS	1	4	1	1	3	1	**2.55**	**7.5**
Westcoast	1	2	1	1	3	1	**2.45**	**5.8**
Enbridge	0	3	0	1	3	1	**2.30**	**8.1**
Northern Border	2	4	1	1	2	1	**2.00**	**6.9**
GTN	2	3	1	1	2	1	**1.95**	**7.0**
Iroquois	1	4	1	1	2	1	**1.85**	**7.0**
M&NP	0	2	0	1	2	1	**1.55**	**6.4**
Alliance	0	0	0	1	1	1	**0.75**	**6.3**

TransCanada recognized the subjectivity of the analysis but submitted that it provides a transparent framework upon which to assess the relative risk factors. TransCanada also asserted that its analysis was more transparent and credible than CAPP's business risk analysis. TransCanada viewed CAPP's analysis as superficial and submitted that it suffered from the same criticisms that had been levelled by CAPP at TransCanada's analysis.

Addressing CAPP's criticism that TransCanada minimized the impact of differences between Canadian and US regulation and also minimized the failure of US pipelines to recover their allowed returns, TransCanada argued that US pipelines have more short-term earnings volatility, which is compensated through higher expected and achieved returns, but that there is no meaningful difference in long-term regulatory policy, which allows US pipelines a fair opportunity to recover their investment. TransCanada also submitted that actual returns provide some indication of exposure to short-term risk but no insight into how a pipeline is being compensated for its long-term risk. Further, in support of its use of allowed returns in this analysis, TransCanada contended that allowed returns are readily available, comparable and free of financial anomalies that cause variations in actual returns.

In response to intervenors' contention that the risk ranking of Vector in TransCanada's business risk analysis should not have been lower than that of the Mainline given Vector's exposure to capacity risk, negotiated rates and other risks, TransCanada stated that risks associated with Vector, as well as the factors that mitigate these risks, were taken into account. TransCanada suggested that the risk associated with the Mainline's low netbacks out of the WCSB outweighed Vector's long-term risks.

With respect to criticism of the authorized ROE that TransCanada used for Vector and PNGTS, TransCanada submitted that the correct after-tax ROE for PNGTS was actually slightly higher than the number TransCanada used. For Vector, TransCanada acknowledged that it used an ROE from an earlier period since it did not have the most recent number.

Position of Intervenors

CAPP

CAPP submitted that TransCanada's analysis is seriously flawed, largely subjective, and presents an inaccurate picture of relative risks. CAPP found the arbitrary distinction between short-term and long-term risk that TransCanada drew to be essentially meaningless and fundamentally a false dichotomy. CAPP submitted that risk realization over the long-term is nothing more than a yearly comparison of actual returns to allowed returns. CAPP contended that the weighting of risk should be greatest for the short-to-medium term rather than the long-term, since the present value of risk events that occur several years into the future is much less than the value of risk events occurring in the immediate future. Further, this effect, CAPP contended, is compounded by depreciation allowances that leave even smaller amounts at risk in future years.

CAPP suggested that TransCanada overstated its own risks and understated those of other pipelines. This, it suggested, is most obvious in the comparison with Vector, which TransCanada assessed as being less risky than the Mainline even though Vector has recourse rates designed to the pipeline's capacity, although it is not fully contracted; has negotiated rates below its maximum rates; offers discounts for 30 percent of its capacity; has a marketing affiliate that assumes the risks of some of the capacity; has deferred recovery of depreciation far into the future; and has had very low returns historically (ROE of 3.7 percent in 2002 and 3.5 percent in 2003). CAPP stated that other pipelines assess their own risk as higher than that portrayed by TransCanada. These pipelines include PNGTS, Iroquois and the US affiliate of M&NP, which shares some of the same risks with M&NP in Canada. Northern Border was also assigned a much lower rating of long-term revenue and cost risk by TransCanada than the Mainline even though it too has an expiring contract portfolio and draws from the WCSB. CAPP questioned the fact that TransCanada sees diversity of supply as a factor reducing risk for pipelines like Iroquois and Northern Border but not for the Mainline.

It was noted by CAPP that 70 percent of the weighting falls on a single factor, the long-term revenue and cost risk category, for which TransCanada assigned itself, and no other pipeline, the highest rating of four. In all other categories TransCanada viewed the Mainline as having little or no risk. CAPP stated that this long-term revenue and cost risk category dominates the final index rankings. If the ratings were reversed so that short-term revenue and cost risk had the 70 percent weighting and the long-term revenue and cost risk weighting was 15 percent, while others stayed the same, the Mainline's index score would fall from 2.9 to 0.7. CAPP suggested that this indicates the extreme sensitivity of the rankings to the assumed weights.

According to CAPP, TransCanada's assignment of risk is heavily influenced by its view of the Mainline as the swing pipeline. CAPP claimed that if the swing pipeline hypothesis is rejected, the ratings would collapse.

CAPP also submitted that TransCanada minimized the impact of differences in Canadian and US regulation. CAPP contended that Canadian pipelines face considerably less business risk than do US pipelines and that this affects both their financial performance and their risk profile. Factors that CAPP identified as increasing the risk of US pipelines include risk of underutilization, construction cost overrun risk, the risk of having to bear costs associated with negotiated rates and discounting, and less use of deferral accounts. CAPP also observed that in the US, the downside risk under regulation includes bankruptcy, which has happened at both the federal and state level.

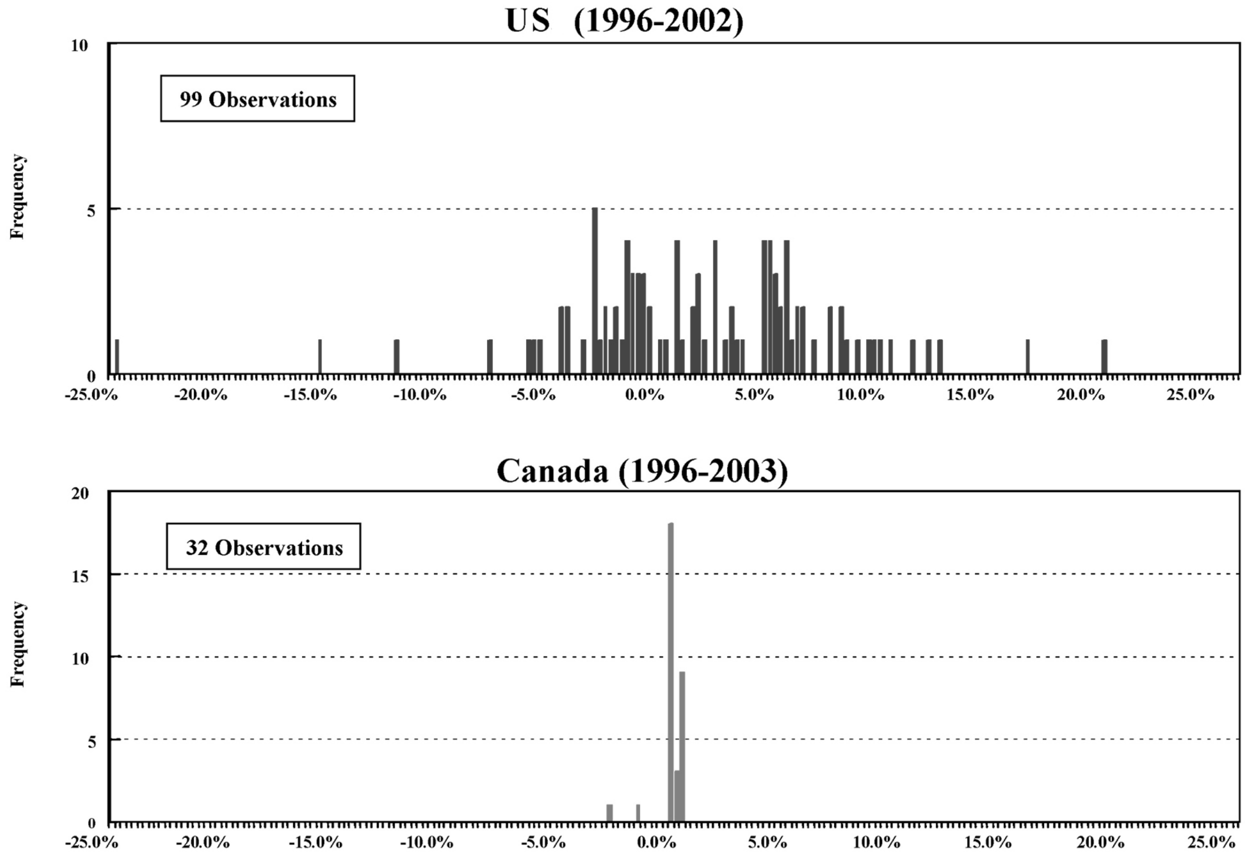
In support of its position on the difference between Canadian and US regulation, CAPP filed an analysis of authorized and earned returns for US and Canadian pipelines (see Figure 5-1). This showed Canadian returns slightly above but very close to authorized levels, while US returns varied widely from authorized levels, both positively and negatively, although skewed toward a positive variance. CAPP submitted that if the regulatory risk between the two systems were similar, one would expect to see a similar pattern between the two countries, which is not evident in the data. CAPP further observed that the statistical result for the US is consistent with regulatory policies that shift more risk to pipelines. With higher risk, one would expect to see the greater variability in excess returns and a greater average excess return as an inducement to accept more risk.

Other concerns expressed by CAPP were that TransCanada did not give proper weight to the failure of some of the pipelines to earn their allowed returns, which reflects the higher risk imposed on US pipelines; relied on inaccurate returns for Vector; and tended to overstate risk because the tendency of revenue and cost to move together was not taken into account. CAPP noted that TransCanada's risk categories were not compatible with the five risk factors assessed by the Board and raised concerns (discussed in Section 5.2.1 of these Reasons for Decision) about comparisons to Alliance, M&NP and Enbridge.

Coral

Coral argued that the relative business risk analysis was not appropriate or useful for a number of reasons. Coral suggested that TransCanada's use of the term short-term risk to describe earnings falling short of the expected return, and long-term risk to describe non-recovery of all or part of capital, does not describe the risks well since variability is a long-term phenomenon and, in principle, non-recovery risks exist even in the short term. Coral observed that parties tend to think of non-recovery risk as long term because in the short to medium term, they do not expect the Mainline to have difficulty recovering its costs. Coral asserted that TransCanada's position that non-recovery or truncation risk, with a 75 percent weighting, is three times more important than variability risk, with a 25 percent weighting, is not credible. Coral also argued that the decline in the outstanding rate base due to depreciation reduces investors' exposure to risk despite the potential for some error in the determination of the depreciation rate. This means that the heavy emphasis on non-recovery risk is excessive.

Figure 5-1
CAPP's Analysis of Actual Returns Less Allowed Returns for US and Canadian Pipelines



With respect to TransCanada's view that contract terms are a key determinant of business risk, Coral submitted that in the context of non-recovery risk many years in the future, it does not make a significant difference whether a pipeline's outstanding contract term is one year, three years, or six years. In this respect, Coral noted that the pipelines in the analysis, other than Alliance, are in similar circumstances to the Mainline.

In addition to the issue of weighting between long-term and short-term risks discussed previously, Coral suggested that the methodology appeared to be biased, citing an exaggeration of the Mainline's risks and the selection of routes in the netback analysis. Like CAPP, Coral disagreed with the rankings TransCanada assigned to the various pipelines and viewed them as arbitrary and subjective. Coral was sceptical about the value of the netback study, which was a factor in TransCanada's assignment of risk scores.

Lastly, Coral was of the view that the relationship that such a study should be looking for is between risk and the cost of capital, not risk and allowed return. Coral argued that one cannot assume that allowed returns reflect the true cost of capital for either the Canadian or US pipelines used in the analysis.

Ontario

Ontario also argued that the methodology and the analysis were flawed and the outcomes not meaningful. Ontario contended that the inclusion of six US pipelines compared with three Canadian pipelines led to a bias because of the higher risks and higher returns under the US regulatory regime. Until requested, the analysis did not include Westcoast even though that pipeline faces virtually the same business risks, including gas supply from the WCSB, pipe-on-pipe competition, and an increase in short-term contracts. Ontario noted that the information base was not the same for each of the companies since TransCanada had insider knowledge of some companies but not others.

5.2.3 Comparable Investments Available to TransCanada

Position of TransCanada

TransCanada noted that in the RH-4-2001 Decision, the Board gave little weight to evidence on comparable investments provided by TransCanada because it was limited, given confidentiality concerns, and of a nature that did not allow parties to test the claims made with respect to the relative business risk and cost of capital associated with those projects. In this proceeding, TransCanada attempted to provide additional information.

TransCanada suggested that, since it is the investor in the Mainline, the returns available to TransCanada from investing in other enterprises of like risk to the Mainline should be considered as a step in addressing the comparable investment standard. TransCanada provided evidence on alternative uses of capital available to TransCanada in the form of five US pipelines in which it has an interest, (GLGT, Iroquois, Northern Border, PNGTS and Tuscarora Gas Transmission) as well as four power projects (Curtis Palmer Hydroelectric Project, Sundance Power Purchase Agreement, ManChief Power Company, LLC and Bécancour Power Project). It also provided three pipeline investment alternatives available to third party investors (Enbridge, Alliance and M&NP). Each of these 12 investments was compared with the Mainline. This list did not include all of TransCanada's investments but only those which TransCanada considered to be of comparable risk to the Mainline. The list also excluded pipelines whose ROE is based on the RH-2-94 Formula or a similar methodology. According to TransCanada, the power investments included are characterized by long-term contracts with creditworthy counterparties. TransCanada views these contracts as being similar to cost of service methodology since most, if not all, changes in input costs flow through to customers.

With respect to US pipelines, TransCanada acknowledged that risks associated with US pipelines are not the same as the Mainline, but submitted that the difference in risk did not warrant the magnitude of the difference in allowed and achieved returns. In particular, it pointed to the difference between the returns of the Mainline and those of interconnecting pipelines carrying the same gas. TransCanada also noted that the differences in regulatory procedure between Canada and the US are not so great as to make these kinds of comparisons irrelevant and that when it comes to the element of risk that matters most to investors, namely long-term earnings and capital cost recovery, the regulatory regimes on both sides of the border have fundamentally the same design.

With respect to CAPP's position that a firm will have opportunities above its cost of capital but will benefit shareholders by investing in all projects which earn the cost of capital or above, TransCanada submitted that there are hidden costs associated with undertaking too many projects. Consequently, projects which are just at the cost of capital will turn into projects which do not earn their cost of capital.

TransCanada argued, in response to Coral's concern about TransCanada's comparable earnings information being a form of the comparable earnings test, that it did not provide this information to estimate the cost of capital, as a comparable earnings test does, but rather to demonstrate that TransCanada has alternative investments of comparable risk that offer higher rates of return.

TransCanada concluded that the comparisons with these investments support an increase in the equity ratio to 40 percent because these investments yield higher returns than the Mainline with similar or less risk.

Position of Intervenors

Intervenors raised a number of conceptual problems with the analysis and concerns about the specific information provided. CAPP stated that the investment opportunities available to TransCanada are irrelevant. A firm such as TransCanada will have multiple investment opportunities with comparable risk and with a range of returns above its required cost of capital. It should undertake all those which have a return exceeding its cost of capital. However, the returns of these investments do not determine the firm's cost of capital. Consequently, CAPP contended that while TransCanada may have better investment opportunities of comparable risk to the Mainline, this has nothing to do with a fair rate of return for the Mainline.

CAPP argued that since TransCanada's management works to ensure that its investments are earning above their cost of capital, these returns do not necessarily indicate the actual cost of capital. CAPP pointed out that the returns on these investments already form part of the broader market data that informs the tests for estimating the cost of capital. CAPP also noted that the cost of an acquisition is a factor in determining return expectations and would have influenced the return expectations of the projects that TransCanada identified in its analysis.

Even if these alternative investments were relevant, CAPP contended that TransCanada's power projects are riskier than the Mainline. CAPP stated that power risks, as identified in TransCanada's annual report, include plant availability, fluctuating market prices, regulatory risk related to restructuring of the electricity industry, risk associated with weather and risks related to uncontracted capacity. CAPP also observed that the power businesses lack the regulatory compact that the Mainline enjoys. Coral noted that there was no objective evidence on the record that the power businesses are of comparable risk.

CAPP contended that TransCanada had put this information forward primarily to support a higher return on equity, which was not at issue in this proceeding, rather than to address capital structure.

Both Coral and CAPP made the point that the sample of investments was selective. Coral raised concerns about the lack of earnings information including book returns on equity, capital structures and debt costs. Coral argued that the information provided was largely the owner's own forecasts of earnings. CAPP also expressed concern about the limited nature of the data due to confidentiality concerns.

Coral argued that it is inappropriate to use regulated firms when comparing the appropriate return of the Mainline with other companies because it makes the analysis circular. In doing so, the Board would be basing its decision with respect to the Mainline on what other regulators do. Coral contended that TransCanada's comparable investment information is actually a version of the comparable earnings test but without its rigour. Coral noted TransCanada's statement that the equity risk premium and the discounted cash flow cash flow analyses are market-based approaches such that stock prices adjust if authorized returns are too high or too low. Consequently, the circularity issue is not a concern using these approaches. However, with returns based on book values, as TransCanada's comparable investment information is, the circularity issue remains.

Lastly, both CAPP and Ontario submitted that there are major differences in US and Canadian regulatory frameworks that render the comparison with US pipelines inappropriate.

5.2.4 Views of the Board

Comparisons to Alliance, M&NP, Enbridge and Westcoast

The Board finds that comparisons with the returns of other pipelines of similar risk may be informative, provided that circularity concerns are properly addressed and that comparisons take into account differences in circumstances.

The Board finds that since the returns of Alliance, M&NP, Enbridge and Westcoast did not result from regulatory decisions following contested cost of capital hearings, their returns can be examined without raising concerns of circularity.

With respect to differences in circumstances, the Board notes that some of these pipelines' returns were set at a time when the cost of capital was higher than it is currently. Further, two of the pipelines, Alliance and M&NP, locked in their returns for a number of years. A higher return may be required for bearing the risk associated with locking in returns or rates over an extended period of time. TransCanada recognized this when it stated that generally a higher ROE would be required for locking in a return for 15 years rather than for five years. To make comparisons relevant, adjustments to the returns of these pipelines to reflect these different circumstances are warranted.

The Board does not agree with TransCanada's proposition that Enbridge is of comparable risk to the Mainline. The Board notes that it has traditionally viewed oil pipelines as riskier than gas pipelines, given oil pipelines' common carrier status supported only by monthly nominations, and because of operational complexities arising from the multi-product nature of their operations. None of the evidence presented by TransCanada supports the conclusion that the changed environment in which the Mainline operates has reduced or eliminated these differences in business risks. Further, even if these pipelines were of comparable risk, the Board notes that Enbridge's financial parameters have been determined through negotiation for the past decade and are reflective of the package agreed to for an oil pipeline at the time those settlements were negotiated, not of cost of capital for a gas pipeline in 2004. The Board gave no weight to the comparison with Enbridge.

The Board is of the view that Westcoast is of similar, albeit not necessarily identical, risk to the Mainline and that its recently agreed upon common equity ratio reflects current conditions. However, the Board notes that Westcoast's equity ratio is a result of a negotiated settlement that specifically states that no single component of the agreement should be considered as acceptable to Westcoast or any of the stakeholders in isolation from all other aspects of the agreement. Nonetheless, Westcoast's agreed upon equity ratio provides some evidence that the Mainline's current equity ratio is not considerably underestimated.

The Board does not agree with TransCanada's evidence suggesting that the Mainline faces more business risk than M&NP, noting that contracts can mitigate risks, but cannot eliminate them and that M&NP's backstop arrangements will expire in approximately 15 years. Further, the Board is of the view that TransCanada failed to adequately consider differences in circumstances facing M&NP. In the GH-6-96 Decision,[48] the Board concluded that M&NP can be viewed as having the same business risk as other Group 1 pipelines, but that it faces substantially different circumstances. The Board noted in that Decision that M&NP was a greenfield project, that its only sources of gas were new and untested fields, that it would be serving an untested market in Canada, and that it was facing significant competition for its anchor market in the US Northeast. The return of M&NP reflects these different circumstances. In addition, any comparison with M&NP must take into account that the return was locked in for a number of years. With respect to TransCanada's suggestion that M&NP's regulatory risk is lower because it is operating under a multi-year settlement, the Board does not accept that the existence of such a settlement has a measurable impact on regulatory risk.

The Board accepts that the level of risk faced by Alliance is sufficiently similar to the Mainline to make comparison relevant. However, when making comparisons, there is validity in adjusting Alliance's return to account for differences in circumstances. In particular, prior to comparing it with the Mainline, the return of Alliance should be adjusted to reflect the

48 National Energy Board GH-6-96 Reasons for Decision, Sable Offshore Energy Project and Maritimes & Northeast Pipeline Project, December 1997, at p. 15

different risk-reward relationship of the two pipelines and the cost of capital environment that existed at the time that Alliance's return was set. Unlike the Mainline, Alliance took on construction cost risk, locked in its return over an extended period of time, and took on some capacity risk. On the other hand, Alliance's long-term contracts tend to mitigate, in part, these additional risks. Comparison with Alliance's return ought to account for the different set of circumstances, including construction cost risk, whether such a risk was mitigable or not, and differences in the cost of capital and interest rate environment that prevailed at the time the return was set.

In summary, while the Board finds the comparisons with Alliance, M&NP and Westcoast informative and qualitatively useful, the different circumstances of these pipelines make it difficult to use these comparisons to arrive at a definitive equity ratio for the Mainline.

Relative Business Risk Analysis

The Board recognizes that TransCanada attempted to address, through its relative business risk analysis, the concerns expressed by the Board in its RH-4-2001 Decision about meaningful comparisons between pipelines. The Board finds the framework for TransCanada's relative business risk analysis to be transparent and systematic. As such, it helps guide and focus the discussion and is a convenient way of summarizing TransCanada's viewpoint. It also provides a useful mechanism for testing the sensitivity of various assumptions.

However, while the Board found the framework useful, it disagrees with some of the assumptions made in TransCanada's analysis, including the weights to be applied to various categories, the ratings assigned to various pipelines, the pipelines included in the analysis, and the returns used by TransCanada. With respect to the issue of the appropriate weights for short-term as opposed to long-term factors, the Board does not accept the implication of TransCanada's analysis that the factors that increase earnings variability in the short-term represent little or no risk in the long-term. The Board notes that the results of the analysis were highly sensitive to the assumptions made with respect to relative weights and the assignment of risk rankings.

With respect to comparisons with US pipelines, the Board's view is that these companies are different businesses operating in a different regulatory, policy and financial context. These differences limit the meaningfulness of direct comparisons between the returns of Canadian and US pipelines. The Board notes that US pipelines are subject to risks not borne by the Mainline, including, among others, risk of underutilization, construction cost overrun risks and risks associated with discounted and negotiated rates. As evidence of the regulatory differences between the two countries, the Board notes CAPP's evidence pertaining to earnings variability in the two countries (see Figure 5-1).

TransCanada acknowledged that risks associated with US pipelines are not the same as the Mainline, but contended that the difference in risk did not warrant the magnitude of the difference in allowed and achieved returns. While providing a framework for comparing various pipelines, TransCanada's relative business risk analysis did not adequately address differences in risk between US and Canadian pipelines. Accordingly, the Board gave little weight to the return evidence of US pipelines.

The Board notes that TransCanada's risk rankings of various pipelines were influenced by its views of the Mainline as the swing pipeline, a view that the Board did not find persuasive, as discussed in Chapter 4.

The Board also had serious concerns about the subjectivity and reliability of CAPP's risk rankings for various pipelines. Overall, the Board gave little weight to either TransCanada's relative business risk analysis or to that of CAPP; however, they were useful tools for examining the evidence and positions of the parties.

Comparable Investments Available to TransCanada

The Board agrees with intervenors that the earnings information for the group of pipeline and power investments selected by TransCanada for comparison does not provide information useful in assessing the cost of capital for the Mainline. However, the Board is cognizant of TransCanada's statement that this information was provided, not to estimate the cost of capital, but to demonstrate that TransCanada has alternative investment opportunities available that it considers to be of comparable risk.

The Board notes that the credit rating agencies and equity analysts view the power business as riskier than the Mainline, as acknowledged by TransCanada's witnesses. The Board does not accept that the power projects put forward by TransCanada as alternative investments are of comparable risk to the Mainline, even though the selected power investments may be of less risk than TransCanada's power investments as a group, or of power investments in general. In this regard, the Board finds it significant that, unlike the Mainline, these selected power investments are not subject to a regulatory compact which influences the risk-reward framework for an investment. Further, little or no information was provided regarding the way in which the power investments were financed. Consequently, the Board placed little weight on the information on power investments provided by TransCanada.

Conclusion - Other Comparable Investments

Overall, the comparisons with Canadian pipelines, the relative business risk analysis and the evidence pertaining to alternative investments available to TransCanada suggest that the current equity ratio of the Mainline is not considerably understated.

Chapter 6

Financial Integrity and Capital Attraction

Position of TransCanada

TransCanada indicated that there is a legal requirement for the Board to determine a return that is fair to the equity investor in the Mainline, and that will allow the Mainline to compete successfully for the capital necessary to fund its anticipated and potential requirements.

It was submitted by TransCanada that an overall return on capital (ATWACC) of 6.3 percent (deemed equity ratio of 40 percent, ROE of 9.56 percent, and after-tax cost of debt of 4.14 percent) would improve the Mainline's current financial integrity and, in turn, its ability to attract capital on a stand-alone basis. TransCanada expressed the view that the currently allowed return on capital for the Mainline does not meet the financial integrity standard. It contended that, at present, the Mainline can attract capital but only to maintain the going concern value of the asset (for example, to invest in maintenance capital). In that respect, TransCanada indicated that it will invest the necessary capital to maintain standards of safety and security on the Mainline at least at their current levels. It also suggested that on a stand-alone basis, the Mainline would attract capital at higher cost and on more restrictive terms and conditions than TransCanada.

TransCanada estimated the Mainline's capital expenditures to be $44 million in 2004, but submitted that the Mainline's ability to access capital markets in the short-term should not be the issue. TransCanada indicated that the Mainline's ability to access capital in the future depends upon the returns available to equity investors and the financial stability and creditworthiness that can be demonstrated by TransCanada to fixed income investors. TransCanada also discussed the importance of US capital markets and viewed the US as an important source of capital for future investments.

According to TransCanada, credit ratings provide an indication to suppliers, customers, and investors regarding the financial stability of a company. TransCanada suggested that credit ratings are a critical element in determining a company's ready access to the capital markets and that credit ratings and liquidity concerns have risen to the forefront of investor attention.

TransCanada indicated that it currently has a credit rating of 'A2 stable' from Moody's Investors Service (Moody's), 'A stable trend' from Dominion Bond Rating Service (DBRS) and 'A-/negative outlook' from S&P. TransCanada submitted that ratings agencies are demonstrating a growing concern with the weak financial profiles of Canadian utility companies and there have been several downgrades over the past three years reflecting these concerns.

TransCanada submitted that if regulatory bodies do not respond to the changes driven by competitive and market realities, Canadian utility companies will experience further credit erosion and, in turn, loss of financial flexibility. TransCanada contended that this erosion would result in its downgrade unless the Board increases the deemed common equity ratio of the Mainline.

In TransCanada's view, an increase in the Mainline's return on capital, through an increase in the equity ratio, is required to achieve appropriate coverage on an interest and cash flow basis. While noting that S&P and possibly Moody's now place greater reliance on other ratios, TransCanada maintained that an interest coverage ratio of 2.0 for the Mainline would not be sufficient to support an 'A' credit rating.

TransCanada indicated that S&P relies on three key global utility benchmark ratios: funds from operations (FFO) interest coverage; FFO to total debt; and debt to capital. However, TransCanada contended that S&P has a stated policy of placing greater emphasis on the two FFO ratios than on the debt to capital ratio. Table 6-1 summarizes the Mainline's various financial ratios from 1999 to 2003 and resulting ratios at various levels of common equity for 2004; namely FFO to total debt, FFO interest coverage, and interest coverage.

Table 6-1
Mainline Financial Ratio Summary

Historical Mainline Ratios

Year	1999	2000	2001	2002	2003
FFO to Total Debt [1] (percent)	8.9	9.3	9.9	10.8	12.3
FFO Interest Coverage (times)	1.99	2.06	2.13	2.21	2.40
Interest Coverage[2] (times)	1.54	1.67	1.71	1.86	1.91

Resulting 2004 Mainline Ratios at various Equity Ratios

Equity Ratio (percent)	33	34	35	36	37	38	39	40
FFO to Total Debt [1] (percent)	12.2	12.5	12.9	13.2	13.6	14.0	14.3	14.7
FFO Interest Coverage (times)	2.45	2.48	2.50	2.52	2.54	2.55	2.57	2.59
Interest Coverage without redemption (times)[3]	1.94	n.a.[5]	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Interest Coverage with redemption (times)[4]	1.93	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	2.20

1 The Mainline's 2004 FFO to total debt ratios at various equity ratios were calculated using the appropriate FFO reported in TransCanada's response to NEB information request 4.1b, divided by one less the equity ratio and multiplied by the Mainline's capitalization of $8.274 billion as of 30 June 2004 reported in TransCanada's response to NEB information request 1.4.

2 The Mainline's interest coverage ratios for the years 1999 to 2003 were calculated using earnings before interests and taxes (EBIT) from TransCanada's Response to NEB information request 1.35(b) divided by the appropriate interest expense (including JSDs' interest) from TransCanada's response to NEB information request 2.3(a), as updated.

3 Assumes redemption of the 8.75% JSDs and 8.50% Debentures, as per TransCanada's response to NEB information request 2.2(f).

4 Assumes no redemption of the 8.75% JSDs and 8.50% Debentures, as per TransCanada's response to NEB information request 2.2(f).

5 Not available

The target level for each ratio varies depending on the rating level (for example, 'A' or 'BBB') and on the business profile score. The business profile score reflects varying levels of risk within a ratings level. TransCanada noted that S&P assigns a business profile score on a scale of one (lowest risk) to ten (highest risk) to each of the companies it rates in the utility and power sector. TransCanada indicated that its consolidated business profile score is a three and suggested that its power business, on a stand alone basis, would have a business profile score around a six. TransCanada acknowledged that the credit rating agencies and the equity analysts view the power business as more risky than the regulated Mainline. TransCanada also provided evidence stating that S&P expects TransCanada, on a consolidated basis, to maintain a minimum FFO to total debt ratio of 14 percent and an FFO interest coverage of 2.6. The S&P benchmark ratios that are relevant to the Mainline's likely business profile score appear in Table 6-2.

Table 6-2
S&P 'A' Rating Benchmark Ratios for 2004

	Business Profile Score	
	2	**3**
FFO to Total Debt (percent)	12.0 - 20.0	15.0 - 25.0
FFO Interest Coverage (times)	2.0 - 3.0	2.5 - 3.5

TransCanada indicated it is committed to maintaining an 'A' credit rating and expressed the view that if it were downgraded to a 'BBB' credit rating, its ability to access capital markets would be impaired. Its marginal borrowing costs would increase; the value of its outstanding debt would decrease; the amounts made available by lenders would decrease; and the debt term to maturity would decrease. TransCanada submitted that these changes would be exacerbated as several major institutional investors would be required to sell their debt holdings because they would be significantly overweighed in the 'BBB' credit rating category. It noted that institutional investors in Canada maintain investment guidelines that, among other things, restrict the amount of 'BBB' debt they can hold.

TransCanada submitted that the Board regulates the Mainline under the stand-alone principle, which requires the Board to consider the Mainline separately and distinctly from TransCanada. However, TransCanada acknowledged that the Board can and should consider relevant evidence about TransCanada and its credit metrics in reaching its decisions.

According to TransCanada, cross subsidization of Mainline credit is occurring at the consolidated level. To support this view, it referred to a report from S&P that suggested that TransCanada's Canadian pipelines' financial performance and business profile are more in line with a 'BBB+' ratings category, while the consolidated financial profile is rated 'A-'. TransCanada also submitted that the assessments of Moody's and DBRS support its position that the Mainline's current capital structure does not provide sufficient support to the financial integrity of the stand-alone entity.

As further evidence that the Mainline is subsidized by the consolidated entity, TransCanada stated that, over the last five years, it has been moving the capital structure of the consolidated entity towards 40 percent common equity. TransCanada submitted that its unregulated businesses are less leveraged than its regulated businesses, and it is the unregulated businesses that are allowing the consolidated entity to maintain its 'A-' rating.

Position of Intervenors

CAPP expressed the view that no significant changes have occurred in business risk or financial integrity that would justify an increase in the Mainline's deemed capital structure. CAPP submitted that the change in the Mainline's depreciation rate approved in the RH-1-2002 Decision increased the Mainline's cash flow and improved its financial integrity.

CAPP submitted that the Mainline has just as much, if not more, financial flexibility now as it had at the time of the RH-4-2001 Proceeding and there is no need to make changes to the Mainline's capital structure to improve access to capital, particularly since the rate base is declining. CAPP stated that the overall conditions in the bond market indicate that the spreads on corporate debt are tighter now than they were in 2001, such that utilities can access debt markets more easily.

It was suggested by CAPP that the most dramatic re-evaluation of credit standards has occurred as a result of S&P harmonizing credit ratings between the US and Canada following its acquisition of the Canadian Bond Rating Service. CAPP submitted that, as a consequence of this harmonization, S&P has employed a quantitative approach and taken standard ratios and judgments drawn from the US and applied them in Canada with little qualitative adjustment for the different institutional environment.

CAPP expressed the view that the Mainline has a good investment grade bond rating with its currently allowed ROE and common equity ratio and that an appropriate common equity ratio is one that, in conjunction with the allowed ROE, enables a pipeline to maintain its credit and attract capital. CAPP submitted that maintaining credit is not the same as maintaining a particular credit rating and that, in turn, there is no need to target a particular credit rating. CAPP suggested that a sale of TransCanada stock by institutional investors would only be triggered if more than one credit rating agency downgraded TransCanada to the 'B' credit rating range.

CAPP suggested that there is no evidence supporting the contention that the Mainline's capitalization is subsidized by TransCanada's non-regulated businesses. CAPP noted that the capital structure of a firm may be viewed in several ways, and that the common equity ratio in TransCanada consolidated was relatively stable in the 35 percent range over the 2001-2003 period. CAPP noted that the 33 percent deemed equity in the Mainline is not out of line with the figures for the consolidated firm.

With respect to TransCanada's contention that it has been moving the consolidated entity's capital structure towards 40 percent equity, CAPP noted that just prior to TransCanada's acquisition of GTN, the consolidated balance sheet included over one billion dollars in cash, and TransCanada reported a common equity ratio of 39.1 percent for the consolidated entity. This increase in the consolidated equity ratio, according to CAPP, was temporary while TransCanada was accumulating cash to fund its acquisition of GTN. On 1 November 2004, TransCanada closed the GTN deal, which was financed through a combination of cash and assumed debt, resulting in a consolidated common equity ratio of 34.8 percent on a pro forma basis, which was in line with what it had been since 2001.

CAPP also pointed to the RH-2-94 Decision, in which the Board indicated that it was not convinced that evidence regarding a consolidated equity ratio that is different from the deemed ratio necessarily indicates the existence of cross subsidization, and that the primary issue was whether or not there is an impact on debt costs.

Ontario contended that the Mainline's financial integrity remains strong, and that it has the ability to attract capital, if necessary. Ontario suggested that TransCanada's application relies excessively on the reports of credit rating agencies, and in particular S&P. Ontario noted that TransCanada was not downgraded in 2004 and submitted that there is no evidence that the company was in danger of a credit downgrade by S&P, DBRS, or Moody's.

Coral submitted that there is little difference between the capital structures of the non-regulated businesses, TransCanada's Canadian regulated pipelines, and the consolidated entity.

Views of the Board

The Board is of the view that the Mainline's financial integrity has improved continuously over the last five years, arising in part from higher depreciation rates and a higher common equity ratio. As shown in Table 6-1, the Mainline's key financial ratios have improved each year from 1999 to 2003. In the Board's view these financial ratios indicate that the Mainline has the ability to meet its current and future financial obligations.

While the Board must regulate the Mainline as a stand-alone entity, the Mainline accesses capital markets through its parent. Therefore, it is affected by TransCanada's credit ratings. The Board notes that, while there are some differences in opinion amongst the three credit rating agencies (DBRS, S&P, and Moody's) concerning TransCanada's financial integrity, the underlying message from these agencies is that, given the evolving nature of the business, TransCanada's Canadian regulated pipelines, including the Mainline, should lower their financial risk. The Board also notes the comment in a 2004 S&P published report to the effect that TransCanada's Canadian pipelines' financial performance and business profile are more in line with the 'BBB+' ratings category.

The Board does not consider it appropriate to set a specific credit rating target. However, the Board accepts that should credit rating agencies downgrade TransCanada below the grade Canadian institutional investors generally require for the majority of their holdings, it could increase the Mainline's cost of debt and equity capital, and limit the number of investors able to hold TransCanada's securities. Although the Mainline's declining rate base and associated revenue earning potential may mean that the maintenance of a high rating in the future will become increasingly challenging, at this time, the Board considers the maintenance of a strong financial position to be a prudent objective for the Mainline.

The Board is not persuaded that the Mainline is being subsidized by TransCanada's unregulated businesses. The Board acknowledges that there are several acceptable accounting approaches to present and compare the Mainline and consolidated capital structures. However, in order to assess whether cross subsidization is taking place, the Board considers it most appropriate to look at consolidated capital structures that exclude cash intended to fund large-scale acquisitions and include non-recourse debt of joint ventures. While the Board recognizes TransCanada's stated objective to move the equity ratio of the consolidated entity towards 40 percent, the Board is of the view that the Mainline is a low-risk pipeline, and need not be capitalized in the same manner as TransCanada's consolidated business. TransCanada has been diversifying into operations that are riskier than its pipeline operations, and its consolidated capital structure should reflect the consolidated risk, not that of the Mainline only.

Although the key financial ratios indicate that the Mainline's financial integrity has improved over the last five years, given the market's perception of the Mainline's level of prospective business risk, a reduction in financial risk, through an increase in its common equity ratio, is warranted in order to ensure that the Mainline continues to maintain its financial integrity and its ability to attract capital on reasonable terms and conditions.

Chapter 7

Capital Structure

For reasons summarized in previous chapters, TransCanada sought approval of a common equity ratio of 40 percent for the Mainline, while all active intervenors expressed the view that the Mainline's equity ratio should remain unchanged at 33 percent.

Views of the Board

As recognized by TransCanada in final argument, the determination of fair return is not an exact science. Although the law is clear as to the standards the Board must meet in setting a fair return (see Chapter 2), what weight a specific piece of evidence or methodology should be given is, as was stated by the Federal Court of Appeal in *TransCanada v. NEB,*[49] a matter of judgment.

In these Reasons, the Board has expressed its views in respect of the main elements of evidence and argument presented by TransCanada and the intervenors. Except in situations where the Board has indicated that it gave no weight to a particular element, the Board found all of the evidence presented relevant and useful. Indeed, in those instances where the Board stated that it gave limited weight to an element, this does not indicate that the element was of questionable or doubtful value, but illustrates the fact that in this proceeding, no single piece of evidence was determinative of the Board's decisions. Rather, it is the body of the evidence, that is, the combined effect of several factors, many of which were given limited weight individually, that guided the Board's judgment.

Having considered all the evidence presented, the Board is of the view that a capital structure comprised of 36 percent deemed common equity and 64 percent debt is most appropriate for the Mainline. In the Board's view, a 36 percent equity ratio recognizes the increase in business risk to which the Mainline is exposed.

In coming to this determination, the Board has explicitly considered the standards set out in Chapter 2 of these Reasons. As discussed in that chapter, it is the Mainline's overall return on capital, resulting from the combination of the Mainline's capital stucture, ROE and cost of debt (set out in Section 8.1), that must be examined in light of these standards. When examining the cost of capital for the Mainline, the Board is of the view that, since the Mainline's tolls recover the actual rather than the market cost of debt, establishing a fair total equity return is the paramount

49 *TransCanada v. NEB, supra* note 8 at para. 32

concern in this case when ensuring that a fair return on capital has been determined.

The Board finds that the overall equity return and overall return on capital resulting from the decisions in this hearing will ensure that the Mainline's returns meet the comparable investment standard. The returns will be in line with those of Canadian pipelines found to be of comparable risk. Further, the Board finds that the resulting risk-reward profile of the Mainline will not be out of line with that of other comparable investments presented in this hearing.

The Board is also of the view that a common equity ratio of 36 percent and the resulting overall return on capital will meet the financial integrity and capital attraction standards. Given the Board's assessment of the Mainline's business risk, the resulting Mainline financial ratios will be reflective of a strong credit rating for a low risk utility. With the resulting financial parameters, the Mainline will continue to maintain and even improve its financial integrity and its ability to attract capital on reasonable terms and conditions. In the Board's view, the Mainline's resulting level of financial risk will be commensurate with the level of business risk it faces.

Decision

The Board approves an increase to the Mainline's common equity ratio from 33 percent to 36 percent.

The Board approves a percentage of debt in the Mainline's capital structure of 64 percent.

Chapter 8

Other Matters

8.1 Cost of Debt

TransCanada's applied-for 2004 revenue requirement reflected an average cost of debt of 8.73 percent. The average applied-for amount and cost of funded debt reflected TransCanada's proposed redemption in July 2004 of the 8.50% Debentures and the 8.25% JSDs.

TransCanada initially sought a determination that the actual incurred cost of debt allocated to the Mainline was reasonable, but withdrew its request for such a direction in its 29 July 2004 evidence. TransCanada did not redeem the 8.25% JSDs in 2004. The 8.50% Debentures were redeemed, but on 1 November 2004. Nonetheless, TransCanada requested, in its July evidence, that the Board approve the initially applied-for average cost of debt of 8.73 percent, effectively seeking a cost of debt reflective, in part, of a deemed cost, rather than actual incurred cost of debt allocated to the Mainline.

Consistent with the RH-4-2001 Decision, TransCanada estimated the pre-funded cost of debt as being equal to the average cost of the Mainline's funded debt, which is made up of First Mortgage Pipe Line Bonds, Debentures, Medium Term Notes and the JSDs.

With respect to unfunded debt, TransCanada applied for a cost rate of 3.11 percent. In January 2005, TransCanada indicated that its actual cost of short-term financing for the twelve months ended 31 December 2004 had been 2.49 percent.

Views of the Board

The Board is of the view that the cost of debt to be included in the Mainline's 2004 revenue requirement should reflect the actual cost incurred to finance the Mainline's deemed level of debt.

Debt allocated to the Mainline by TransCanada and forming the Mainline's funded debt includes First Mortgage Pipe Line Bonds, Debentures, Medium Term Notes and the JSDs. The Board notes that TransCanada's applied-for cost of funded debt is not reflective of actual cost, since it assumes a redemption that did not occur and another redemption that occurred at a date different than had been forecast. The Mainline's 2004 cost of funded debt should reflect the fact that the 8.25% JSDs were not redeemed in 2004 and the actual date at which the 8.50% Debentures were redeemed. As part of its compliance filing, TransCanada should file revised schedules reflecting these two changes.

The Board notes that the Mainline's funded debt is likely to exceed, at times, the deemed debt level of 64 percent in the Mainline's capital structure. The Mainline capitalization is therefore expected to include a certain level of pre-funded debt. Consistent with the RH-4-2001 Decision, any pre-funded debt should be assumed to have a cost equal to the average cost of the Mainline's funded debt. This approach effectively allocates back to TransCanada a slice of the funded debt, equal to the excess in funded debt, which had previously been assigned to the Mainline.

Should the Mainline's capitalization require the use of unfunded debt, the cost of unfunded debt should reflect TransCanada's actual cost of short-term financing for the twelve months ended 31 December 2004, which is 2.49 percent.

Decision

TransCanada is directed to file as part of its compliance tolls filing detailed calculations of the Mainline's 2004 cost of debt reflecting:

- **a cost of funded debt that reflects that the 8.25% JSDs were not redeemed in 2004 and the actual date at which the 8.50% Debentures were redeemed;**
- **a cost of pre-funded debt equal to the cost of funded debt; and**
- **a cost of unfunded debt of 2.49 percent.**

8.2 Effective Date

The Phase II List of Issues included, as Issue 3, the appropriate effective date for any change to the Mainline's cost of capital. This section focuses on the appropriate date of any change to the Mainline's common equity ratio.

Position of TransCanada

TransCanada's application proposed 1 January 2004 as the effective date to implement any changes to capital structure. TransCanada submitted that the Board can deal with any changes in tolls on a retrospective basis, which would permit the collection of any difference in tolls arising since 1 January 2004 from tollpayers in future rates.

TransCanada noted that it had proposed to redeem the 8.25% JSDs on 30 June 2004 and did not object to any equity thickness that would be awarded for that reason to also be effective 30 June 2004, rather than 1 January 2004.

TransCanada pointed to a heavy regulatory calendar (e.g., NGTL General Rates Application and Generic Cost of Capital proceedings, both before the Alberta Energy and Utilities Board; and the

Mainline Phase I and North Bay Junction proceedings) as the main driving factor behind the date of filing of its 2004 Tolls Application. TransCanada also submitted that other factors that delayed the processing of Phase II were beyond its control. In particular, TransCanada noted that Phase II could not take place until after the Federal Court of Appeal decision was issued on TransCanada's Appeal of the RH-R-1-2002 Decision.

Position of Intervenors

CAPP indicated that it is always easier to implement change on a go-forward basis, but acknowledged that the effective date could be 1 January 2004. In addition, CAPP argued that TransCanada had the duty to file its application early enough for any change to be effective early in the test year.

IGUA expressed its opposition to any retroactive increases in tolls. IGUA submitted that the Board should consider the significance of any cost associated with the retrospective introduction of changes to the Mainline's cost of capital, and if necessary, consider levelling adjustments into the future.

Views of the Board

While the Board would have expected an application seeking a change to cost of capital to be filed much earlier than the end of January of the applicable test year, the Board accepts that the late filing can be explained by the complexity surrounding the appeal by TransCanada of the Board's RH-R-1-2002 Decision. In this instance, the Board is of the view that it would be reasonable to make the changes to the Mainline's capital structure effective 1 January 2004.

Decision

Changes to the Mainline's capital structure shall be effective 1 January 2004.

8.3 Expected Duration of the Decision

While TransCanada's application related to the 2004 Test Year, TransCanada expressed the view that to the extent the company was comfortable with the Phase II Decision, it may be capable of enduring for a period longer than one year.

TransCanada initially argued that the Board has the jurisdiction to make a decision that allows more or less than what is asked for and could therefore make a decision that is for a longer period of time than requested by the Applicant. However, TransCanada submitted that in order to do so, the evidence in this case would need to justify reaching the conclusion that the duration of the order should be something other than what was applied for. In reply argument, TransCanada clarified its position and submitted that the Board should not, in its Decision, be purporting to determine a cost applicable to future years. Nonetheless, the Board could provide guidance in its Decision, similar to that provided in the RH-2-94 Decision, when it expressed the expectation that it did not favour routine readjustments to capital structure.

CAPP argued that the Board was being asked to make judgments about issues and risk factors that span years and decades. As a result, CAPP submitted that the views of the Board in this instance will have an enduring effect. CAPP submitted that a well-founded judgment on issues of an enduring nature should continue to be applied in the future, unless circumstances change. CAPP further submitted that providing guidance as to what the Board would like to see in future proceedings in order to address certain issues would be helpful.

Ontario submitted that although the Board has the theoretical discretion to extend the application of its decision on capital structure for 2004 beyond that year, it would be unwise to do so in this instance. Ontario expressed the view that discretion must be exercised fairly and properly which, it submitted, requires reasonable notice to all potential participants in the proceeding in order to be procedurally fair.

Views of the Board

The Board acknowledges that its decisions in this instance apply solely to the 2004 Test Year but reiterates the statements made in the RH-2-94 Decision that it does not favour routine reassessments of capital structure. However, the Board is always prepared to consider a reassessment of capital structure in the event of significant change in business risk, in corporate structure, corporate financial fundamentals, or other changes of significance.

8.4 Tolls Resulting from this Decision

Views of the Board

The Board notes that the RH-2-2004, Phase I Decision was the subject of two review and variance applications to the Board; one filed by CAPP and one by Coral and the Cogenerators Alliance. At the time of writing this Decision, some aspects of these review and variance applications remain outstanding. Therefore, the Board is of the view that the Mainline's 2004 Tolls should remain interim, at their current level, pending the outcome of those aspects of the review applications that could impact the 2004 revenue requirement.

The Board requests that TransCanada file for approval of final tolls within 30 days of the later of either the release of the Phase II Decision or the Board's disposition of those aspects of the review applications of the Phase I Decision that could impact the 2004 revenue requirement.

When TransCanada files for final 2004 tolls, the Board is of the view that it would be appropriate for TransCanada to adjust the 2005 revenue requirement for the difference between the 2004 interim and 2004 final tolls, along with applicable carrying charges. However, should TransCanada and the TTF prefer another form of adjustment, TransCanada may include such a proposal as part of its compliance filing.

Decision

TransCanada shall file final tolls schedules with the Board for approval within 30 days of the later of either the release of the Phase II Decision or the Board's disposition of those aspects of the review applications of the Phase I Decision that could impact the 2004 revenue requirement. The filing shall reflect the Phase II Reasons for Decision and the decisions of the Board regarding the issues from Phase I.

Chapter 9

Disposition

The foregoing chapters together with Order AO-3-TGI-07-2003 constitute our decisions and Reasons for Decision in respect of those aspects of the 2004 Tolls Application heard by the Board in Phase II of the RH-2-2004 Proceeding.

The Board is of the view that the decisions reached in Phase II of the RH-2-2004 Proceeding are consistent with the comparable earnings, financial integrity and capital attraction standards set out in Chapter 2 of these Reasons for Decisions and will result in a fair return for the Mainline. Further, the Board is satisfied that the decisions reached in this phase of the hearing, in combination with the Tolls and Tariff provisions which were the subject of Phase I, will result in tolls that are just and reasonable for the 2004 Test Year.

G. Caron
Presiding Member

J.S. Bulger
Member

D.W. Emes
Member

Calgary, Alberta
April 2005

Appendix I

Board Ruling on CAPP's Motion of 4 June 2004

Issued by letter dated 30 June 2004.

TransCanada filed its 2004 Tolls Application on 26 January 2004. With respect to cost of capital, TransCanada sought to increase its level of deemed common equity from the current 33 percent to 40 percent and to increase the approved return on equity (ROE) from the current 9.56 percent to 11 percent.

The Board issued Hearing Order RH-2-2004 on 23 March 2004 and stated that it would not be appropriate to initiate procedural steps with respect to Phase II, the cost of capital component of the 2004 Tolls Application, until after the release of the Court of Appeal Decision with respect to TransCanada's Appeal of the Board's RH-R-1-2002 Decision. The Court of Appeal Decision denying TransCanada's appeal was released on 16 April 2004.[1]

On 12 May 2004, TransCanada advised the Board that, in light of the Court of Appeal Decision, it would not seek variance from the RH-2-94 ROE Formula for 2004 which yields an ROE of 9.56 percent. TransCanada also indicated that it would maintain its 2004 Tolls Application position concerning its applied-for capital structure of 40 percent deemed common equity for 2004. On 28 May 2004, TransCanada filed related amendments to the 2004 Tolls Application.

On 4 June 2004, the Canadian Association of Petroleum Producers (CAPP) filed a notice of motion with respect to Phase II. CAPP requested the Board to:

a) direct that the correctness of the RH-4-2001 Decision is not an issue in the RH-2-2004, Phase II Proceeding;

b) direct that evidence as to capital structure must begin and end on the basis that the NEB Formula ROE is the fair ROE;

c) direct that evidence as to capital structure must focus on significant changes that have occurred since the RH-4-2001 Decision;

d) strike the evidence of Drs. Kolbe and Vilbert, Mr. Murphy, and Dr. Carpenter;

e) strike Appendix 1 to Appendix B-2 (Comparable Investments) and Appendices 2 (Business Risk: Company Profiles) and 3 (Business Risk: Comparative Business Risk Ratings) to Appendix B-3[2] in TransCanada's corporate evidence;

f) direct TransCanada to remove from Appendices B-1 (Overview), B-2 (Fair Return Evidence) and B-3 (Business Risk) of its corporate evidence all portions that fail to

1 *TransCanada Pipelines Ltd. v. National Energy Board,* [2004] F.C.A. 149.

2 The identification of the appendices was clarified in TransCanada's comments and CAPP's reply.

conform with directions (a), (b), and (c) above or that relate to evidence that has been struck; and

g) provide such further or other direction as the Board may consider just.

CAPP stated that even though TransCanada has withdrawn the request for an 11 percent ROE, it has not withdrawn the evidence previously filed that supports an 11 percent ROE and has not refocused the evidence on the appropriate deemed level of equity. Consequently, it is left to the parties to "figure out what is and is not relevant to capital structure as distinct from ROE."[3] CAPP notes that it is unfair and inefficient for parties to be faced with large amounts of highly technical and detailed material that is irrelevant.

CAPP noted that while TransCanada's amended application is based on 9.56 percent ROE, TransCanada continues to assert that 9.56 percent ROE is not fair and that a fair return would be 11 percent ROE on 40 percent common equity. CAPP argued that as a matter of law, the fair ROE for 2004 is the ROE produced by the Board's RH-2-94 Formula and that the correctness of the Formula, the RH-4-2001 Decision, and the RH-R-1-2002 Decision is no longer open to question.

It was submitted by CAPP that the fundamental question to be examined is what changes in business risk, in corporate structure, or in corporate financial fundamentals have occurred since capital structure was last decided in the RH-4-2001 Decision.

CAPP further stated that the evidence of Drs. Kolbe and Vilbert derives a fair return of 11 percent ROE on 40 percent common equity from a determination of the overall cost of capital (ATWACC) of sample companies. Under this approach the ROE and capital structure are inextricably linked. Both are contained in the ATWACC; hence if the Board agreed with the ATWACC methodology and 40 percent common equity, it would also be agreeing with the appropriateness of an 11 percent ROE. CAPP concluded that it is unfair and prejudicial to other parties to allow the evidence of Drs. Kolbe and Vilbert to stand.

By letter of 7 June 2004 the Board sought submissions of parties with respect to the motion. On 11 July 2004, the Industrial Gas Users Association (IGUA), and the Cogenerators Alliance and Coral Energy Canada Inc. filed letters in support of CAPP's motion. IGUA submitted that, for evidence regarding the appropriate level of deemed equity to be relevant, it must be confined in its scope to addressing any material changes in circumstances since the final day of the test years covered by the RH-4-2001 Decision. Furthermore, it must focus solely and exclusively on the issue regarding the appropriate level of deemed common equity. IGUA further submitted that the evidence of Mr. Lackenbauer and Mr. Engen should also be struck as it is far too broad and fails to satisfy the relevance test with respect to the appropriate level of deemed common equity issue.

TransCanada filed its answer to the CAPP motion on 16 June 2004. TransCanada submitted that the CAPP motion is entirely devoid of merit and should be dismissed. TransCanada expressed its view that the cost of capital requires *four* distinct decisions by the Board: (1) the forecast cost of debt; (2) the rate of return on equity; (3) the level of deemed common equity; and (4) the fair

3 CAPP motion dated 4 June 2004, at para. 13(b)

return on equity capital. It acknowledged that to date, the Board has only made one of the four determinations: the 9.56 percent ROE. TransCanada did not dispute the applicability of the Board Formula to determine the ROE as the Federal Court of Appeal upheld the Formula approach and TransCanada is not applying for review and variance of the Formula in 2004.

TransCanada stated that "as a matter of law, it is the return on equity capital (not the rate of return in isolation, or the level of deemed equity in isolation) that is subject to the fair return standard."[4] It argued that all of the evidence is addressed to the fair return on equity capital and therefore, all is relevant to the issues that remain to be determined by the Board in Phase II. TransCanada stated that Dr. Kolbe was asked to estimate the fair return on total capital, debt and equity combined, and the fair rate of return on equity at a 40 percent common equity ratio. TransCanada's position is that 40 percent common equity will bring the overall return closer to this level.

TransCanada stated that in respect of Mainline capital structure there is a "clean slate" for 2004 and that the RH-4-2001 and RH-2-94 Decisions do not apply to 2004. It submitted that it is the Board's legal obligation to hear an application that is placed before it and that TransCanada's filing on cost of capital in Phase II is directed to persuading the Board that the fair return on equity capital should be different and higher than that which was determined for 2001 and 2002.

On 22 June 2004, CAPP filed a response to TransCanada, in which it stated that under the method adopted by the Board to determine cost of capital, fair return is simply the arithmetic result of three determinations: (1) cost of debt; (2) ROE; and (3) capital structure. There is no fourth, separate determination of a fair return. The fair return on equity capital is simply the arithmetic result of the ROE and the proportion of deemed common equity in the capital structure. CAPP argued that TransCanada could only raise the fair return on equity in its entirety by putting the ROE into issue which they have chosen not to do.

CAPP also addressed TransCanada's "clean slate" argument and stated that a decision by the Board on capital structure is intended to stand until there are significant relevant changes that warrant a change in capital structure. CAPP noted that the RH-4-2001 and RH-R-1-2002 Decisions applied to 2003, not only to 2001 and 2002 as TransCanada stated. CAPP submitted that TransCanada is seeking to attack the correctness of the RH-4-2001 Decision which is no longer open to question since any possible attack has been closed by the RH-R-1-2002 Decision and the appeal judgment.

Views of the Board

Rate of Return on Equity

The Board notes that all parties who submitted comments on CAPP's motion agreed that the rate of return on equity for the Mainline has been set for 2004 at 9.56 percent by the application of the RH-2-94 ROE Formula. The applicability of the RH-2-94 ROE Formula for the Mainline was continued by the Board's RH-4-2001 Decision. TransCanada sought review and variance of the RH-4-2001 Decision, which was denied by the Board's RH-R-1-2002 Decision. The

4 TCPL submission dated 16 June 2004, at paragraph 17

RH-R-1-2002 Decision was subsequently appealed by TransCanada to the Federal Court of Appeal. The Court denied TransCanada's appeal on 16 April 2004. The opportunity to appeal the Court's decision has expired.

In its reason for judgment, the Court noted that the Board Order TG/TO-1-95, which implemented the RH-2-94 Decision, contained no time limit and therefore continues in force until reviewed or varied by the Board.[5] On 12 May 2004, TransCanada advised the Board that it was not prepared to advance a review and variance application in 2004, and that, in light of the Court Decision, it will not contest the applicability of the RH-2-94 ROE Formula of 9.56 percent to the Mainline for 2004.

On this basis, it is clear that the correctness of the RH-4-2001 Decision and the appropriateness of the RH-2-94 ROE Formula are not at issue in the RH-2-2004 Proceeding. The Board is therefore of the view that it would be inappropriate to consider evidence or arguments that state or suggest otherwise. Given that TransCanada has chosen not to file a review application on this issue, it is not open to it to submit that the appropriate ROE for the Mainline is something other than 9.56 percent, no matter what the views of the company may be. TransCanada cannot do through indirect means, that which it has chosen not to do directly. Therefore, the Board is of the view that TransCanada needs to amend its evidence to eliminate all instances which suggest that the appropriate rate of return on common equity for the Mainline in 2004 is anything other than 9.56 percent.

Capital Structure

The Board notes a clear divergence of views between parties concerning the appropriate evidence to be considered with respect to a determination of capital structure for the Mainline in 2004. CAPP submits that evidence as to capital structure must focus on significant changes that have occurred since the RH-4-2001 Decision. IGUA further submits that the scope should be confined to any material changes in circumstances which have occurred since the last day of the test years covered by the Board's RH-4-2001 Decision. TransCanada on the other hand submits that with respect to capital structure, there is a clean slate for 2004.

The Board is of the view that the law does not prescribe a particular approach to the nature of the evidence that should be filed in support of an assessment of appropriate capital structure. An applicant is therefore free to adopt the focus it deems appropriate in preparing evidence concerning capital structure. The same freedom also applies to any intervenor wishing to file evidence on this issue. The appropriate weight that any specific approach or piece of evidence should be given is a matter subject to argument after the evidence has been heard and is to be determined by the Board in making its decisions, not prior to hearing. In this context, the Board does not consider that it would be appropriate to issue a direction to TransCanada concerning the focus of its evidence pertaining to capital structure.

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5 *Supra* note 1 at paragraph 50

Fair Return on Equity and Fair Return on Capital

The Board has consistently arrived at a determination of the overall level of fair return on equity by applying the approved rate of return on common equity to the deemed level of common equity in a pipeline's capital structure. Under this approach, the Mainline's fair return on equity for 2004 would be the RH-2-94 ROE of 9.56 percent applied to the appropriate level of deemed common equity that will be determined by the Board in Phase II of the RH-2-2004 Proceeding. This approach does not require the consideration of particular evidence pertaining to overall equity return.

Similarly, the Board's determination of overall cost of capital, or return on rate base, has been accomplished by calculating the weighted average of the cost of each component by its share in the Mainline's deemed capital structure. This approach has been recognized by the Federal Court of Appeal in *TransCanada Pipelines Ltd. v. Canada (National Energy Board).*[6]

While the Board is willing to consider alternative approaches to determine the fair return on equity and capital, the Board is mindful that in this instance, any alternative approach considered should recognize that the rate of return on equity for the Mainline in 2004 has already been determined to be 9.56 percent, through the application of the RH-2-94 Formula, and that the RH-2-94 Formula continues in force until reviewed or varied by the Board. Since TransCanada has not advanced a review and variance application in 2004, it would be inappropriate for the Board to consider alternative approaches that directly or indirectly question the correctness of the rate of return on common equity derived by the application of the RH-2-94 Formula to the Mainline in 2004. In other words, the Board is not prepared to undertake, through the consideration of alternative approaches to return on equity or return on capital, an indirect review of the RH-2-94 Decision. Such a review should only be contemplated through a review and variance application filed under subsection 21(1) of the NEB Act, or at the discretion of the Board.

Board Ruling

The Board is of the view that portions of TransCanada's evidence are not relevant to Phase II of the RH-2-2004 Proceeding, as they suggest that the rate of return on equity for the Mainline in 2004 should be other than 9.56 percent. Instances of such examples appear throughout TransCanada's evidence, such that the Board does not consider that it would be practical for the Board itself to go through TransCanada's evidence and decide what portions of it should be struck or amended.

Rather, the Board directs that TransCanada file amendments to its evidence in such a way as to remove any direct or indirect inferences to an appropriate rate of return on equity other than 9.56 percent for the Mainline in 2004 on or before noon, Calgary time, 15 July 2004.

As a result of the impending revised evidence from TransCanada, the Board has decided to amend the deadlines contained in paragraphs 28 and 29 of Hearing Order RH-2-2004. Attached is Order AO-2-RH-2-2004, amending Hearing Order RH-2-2004.

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6 *Supra* to note 1

Appendix II

Board Ruling on CAPP's Letter of 4 August 2004

Issued by letter dated 12 August 2004.

The National Energy Board has received CAPP's letter of 4 August 2004 in which it expressed the view that TransCanada has not complied with the Board's direction of 30 June 2004. The Industrial Gas Users Association filed a letter supporting CAPP's comments on 6 August 2004.

CAPP had filed a notice of motion dated 4 June 2004 requesting, *inter alia*, that the Board strike certain TransCanada evidence from the record on the basis that the evidence asserted that a rate of return on equity (ROE) other than that derived from the Board's RH-2-94 ROE Formula (9.56 percent) was the fair return for 2004.

The Board ruled that as TransCanada had decided not to seek a review of the RH-2-94 ROE Formula, it is not open to TransCanada to submit that the appropriate ROE for the Mainline in 2004 is something other than 9.56 percent. TransCanada was directed to amend its evidence to eliminate all instances which made such a suggestion.

Further, the Board ruled that while it is willing to consider alternative approaches to determine the fair return on equity capital, any alternative approach must recognize that the ROE for the Mainline has been determined to be 9.56 percent. The Board stated that it would be inappropriate for it to consider alternative approaches that directly or indirectly question the correctness of the rate of return on common equity derived by the RH-2-94 ROE Formula.

As a result the Board directed TransCanada to amend its evidence to remove any direct references or indirect inferences to an appropriate rate of return other than 9.56 percent for the Mainline in 2004.

Parties have expressed diverging views on whether ATWACC evidence implies an indirect review of the Board's RH-2-94 ROE Formula. The Board reiterates its 30 June 2004 ruling that it will not allow TransCanada, through its ATWACC or other evidence to do indirectly that which it has chosen not to do directly. However, in the Board's view, TransCanada should be allowed to present its case as it relates to the issues to be addressed in Phase II of the RH-2-2004 hearing in the manner it deems appropriate, so long as the rules of natural justice are respected. While the Board will not, at this time, require TransCanada to further amend its filings, the Board cautions TransCanada and all parties, that it is not prepared to consider this evidence if its purpose is to suggest an indirect review of the RH-2-94 Formula.

Appendix III

Board Ruling on TransCanada's Motion of 12 November 2004

Issued from the Bench on 19 November 2004.

Background

TransCanada PipeLines Limited filed an application with the National Energy Board on January 26th, 2004, for the approval of tolls for the Mainline for 2004. Among other things, TransCanada sought the rate of return on equity of 11 percent on a common equity ratio of 40 percent.

On March 23rd, the Board issued the RH-2-2004 Hearing Order and indicated that it had decided to convene a two-phase oral hearing to consider the application. Phase I was to consider all matters raised in the application with the exception of cost of capital, which the Board indicated, would be heard in Phase II. The Board noted that it would not be appropriate to initiate further procedural steps in relation to the cost of capital component of the 2004 tolls application until after the release of the Federal Court of Appeal decision with respect to TransCanada's appeal of the Board's RH-R-1-2002 Decision.

On April 6th, the Federal Court of Appeal released its decision denying TransCanada's appeal of the Board's Decision in the RH-R-1-2002 Review[1]. By letter dated May 12th, TransCanada advised the Board that, in light of the Court Decision, it would not seek variance from the RH-2-94 ROE Formula for 2004 which yields a rate of return on equity of 9.56 percent for 2004. On May 28th, TransCanada filed related amendments to its 2004 Tolls Application, reflecting the applied for 9.56 percent ROE on a common equity ratio of 40 percent. The Board issued an amended Hearing Order (AO-1-R-2-2004) on June 7th which removed the appropriate rate of return on common equity for the Mainline as an issue to be addressed in Phase I.

The Canadian Association of Petroleum Producers filed a notice of motion on June 4th, 2004 requesting that the Board narrow the issues to be considered in Phase II. The balance of the relief requested focused on having portions of TransCanada's evidence struck from the record.

On June 30th the Board ruled that portions of TransCanada's evidence were not relevant to Phase II of the RH-2-2004 Proceeding, as those portions suggested that the rate of return on equity for the Mainline in 2004 should be other than 9.56 percent. The Board directed that TransCanada amend its evidence to remove any direct or indirect references to an appropriate rate of return on equity other than 9.56 percent for the Mainline in 2004.

On August 4th, the Board received a letter from CAPP in which it expressed the view that TransCanada had not complied with the Board's direction of June 30th. The Board responded

1 *TransCanada PipeLines Ltd. v. National Energy Board, et al.,* [2004] F.C.A. 149

with a letter dated August 12th, which reiterated the points made in its earlier ruling, including the fact that it would not allow TransCanada, through its ATWACC or other evidence, to do indirectly that which it has chosen not to do directly; that is, to seek a review of the RH-2-94 ROE Formula. However, the Board also stated that TransCanada should be allowed to present its case as it relates to the issues to be addressed in Phase II of the RH-2-2004 Hearing in the manner it deems appropriate, so long as the rules of natural justice are respected.

On October 19th, 2004, CAPP filed its evidence with the Board, the subject of which forms the basis of the motion filed by TransCanada.

TransCanada's Motion

On November 12th, TransCanada filed a motion requesting clarification regarding the issues to be considered in Phase II of RH-2-2004 and the parameters for the conduct and disposition of the proceeding. TransCanada requested that the Board hear the motion orally, prior to reply evidence which must be filed by November 25th, in order to give guidance to TransCanada with respect to this evidence, as well as the nature and extent of cross-examination in the hearing. On November 15th, the Board set down the motion for consideration today and allowed for written submissions to be filed by November 18th. Written submissions were received from the Industrial Gas Users Association and le Procureur général du Québec. These comments and the oral submissions made today by TransCanada, CAPP, and Coral Energy Canada Inc. have all been appreciated and have assisted the Board in reaching its decision on this matter.

In reaching its decision, the Board has been mindful of the comments made by parties regarding the efficiency of the process. The Board is of the view that this is a goal worth striving for, and we are of the view that hearing this motion at parties' convenience, before the hearing, and issuing an oral ruling shows our commitment to that goal. However, the Board also notes the comments today that regulatory efficiency cannot override:

- the legal principles;
- the rights of a party to present its case as it determines fit; or
- the needs of the Board to hear all, and the best evidence before reaching a decision.

Request (a) of the Motion

The first request by TransCanada is for a direction that "as a matter of law, the determination that is to be made by the Board in Phase II is the fair return on investment in the TransCanada Mainline for 2004".

The Board is very familiar with the law as set out in *Northwestern Utilities (1929)*, *Hope* and *Bluefield* on this issue. However, the Board notes that TransCanada has chosen not to apply for a review of the rate of return on equity. This hearing is therefore not an examination of all elements of cost of capital or fair return. Hearing Order AO-1-RH-2-2004 identifies the issues which, in the Board's view, require decisions, namely:

1) the appropriate capital structure for the Mainline;

2) the appropriate cost of debt for the Mainline, including any financial impact resulting from debt redemption; and

3) the appropriate effective date for any change to the Mainline's cost of capital.

Both CAPP and TransCanada have stated today that they are not attempting to limit the ability of the other party to present its case. In the Board's view, what was in dispute in the CAPP motion in June, and what is in dispute now, is the methodology that will be employed in order to arrive at a determination of the overall level of fair return on equity. The Board understands that TransCanada is seeking to have the Board consider return using a different methodology than the traditional methodology. To this end, the Board confirms its previous ruling that it is willing to consider alternative approaches to determine the fair return on equity and capital.

However, for the purposes of this ruling, the Board is not prepared to limit itself to the specific wording used in TransCanada's motion. The Board's responsibility according to the *National Energy Board Act* is to set just and reasonable tolls. The determinations which the Board has to make in Phase II of this Proceeding are decisions on the issues set out in the List of Issues, resulting in a decision on the application filed by TransCanada. By making decisions on the issues set out in the List of Issues, and utilizing the rate of return on common equity from the RH-2-94 formula, the end result will be the overall return on investment for the Mainline for 2004. TransCanada is free to submit evidence and argue that an alternative approach should be utilized in making these determinations. The Board cannot, and will not, prior to hearing all of the evidence, make a determination on which approach or approaches should be used.

Request (b) of the Motion

TransCanada's second request is for a direction that "as a matter of law, the issues to be considered in the determination of the fair return on investment in the Mainline for 2004 are not limited to any changes in the business risk and financial integrity of the Mainline since the RH-4-2001 Decision."

The Board has considered the law as set out in the motion and as discussed by parties in their submissions, and agrees with TransCanada that as a matter of law, it is not limited to arguing changes to risk and financial integrity since the RH-4-2001 Decision. As the Board stated in its ruling on CAPP's motion on this very issue on June 30th:

> The Board notes a clear divergence of views between parties concerning the appropriate evidence to be considered with respect to a determination of capital structure for the Mainline in 2004. CAPP submits that evidence as to capital structure must focus on significant changes that have occurred since the RH-4-2001 Decision. IGUA further submits that the scope should be confined to any material changes in circumstances which have occurred since the last day of the test years covered by the Board's RH-4-2001 Decision. TransCanada, on the other hand, submits that with respect to capital structure, there is a clean slate for 2004.

> *The Board is of the view that the law does not prescribe a particular approach to the nature of the evidence that should be filed in support of an assessment of appropriate capital structure.* An applicant is therefore free to adopt the focus it deems appropriate in preparing evidence concerning capital structure. The same freedom also applies to any intervenor wishing to file evidence on this issue. The appropriate weight that any specific approach or piece of evidence should be given is a matter subject to argument after the evidence has been heard and is to be determined by the Board in making its decisions, not prior to hearing. In this context, the Board does not consider that it would be appropriate to issue a direction to TransCanada concerning the focus of its evidence pertaining to capital structure. [Emphasis added]

The Board noted the comments of Mr. Schultz on behalf of CAPP that TransCanada is free to argue a change of approach and that CAPP is not attempting to limit the presentation of TransCanada's evidence. In keeping with our earlier rulings on this matter, while no party may argue that any other is prohibited from arguing an alternative approach, they are free to seek to show the flaws and errors of such an approach.

The Board therefore agrees with TransCanada, that TransCanada is not limited in its evidence to examining changes since 2001.

Request (c) of the Motion

The third request of the motion is for a determination that "as a matter of law, the impact on the Mainline revenue requirement and tolls of an increase in the cost of equity capital for the Mainline is not to be taken into account by the Board in the determination of the fair return on investment in the Mainline."

The Federal Court of Appeal in the *Appeal Decision* acknowledged that customers of the pipeline have an interest in ensuring that the Mainline's costs are not overstated.[2] However, in the Board's view, the Court also found that the impact of tolls on customers is an irrelevant consideration in the determination of the Mainline's cost of equity capital.[3]

While the Mainline's rate of return on equity is not an issue to be addressed in Phase II of the RH-2-2004 Hearing, the Board accepts that the impact of tolls on customers is an irrelevant consideration in the determination of other aspects of cost of capital. Therefore, the Board will not give weight to any evidence pertaining to impact of tolls on customers in making the determinations to be made in Phase II.

Request (d) of the Motion

TransCanada's final request is for the Board to confirm that it will not consider any evidence or permit any cross-examination in Phase II that is inconsistent with the law as stated in its motion. To the extent that the evidence of either TransCanada or CAPP suggests something contrary to this ruling, or any other Board ruling, the Board will not take such evidence into consideration.

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2 *Ibid*. at para. 34

3 *Ibid*. at para. 25-42

At this stage, the Board is of the view that it would be premature to rule on whether an eventual line of cross-examination would be inappropriate.

The Board would like to thank all parties for their submissions, the Board's staff, the court reporters, the interpreters for accommodating the hearing of this motion on such short notice.

Appendix IV

Mainline Throughput Forecasts and Sensitivities

TransCanada: Base Case
(Bcf/d[1])

	2005	2010	2015	2020	2025
Supply					
Conventional	16.6	15.7	14.3	10.9	7.7
Unconventional	0.2	1.0	2.5	3.6	3.9
Net Storage	-0.11	-0.02	-0.02	0.00	0.00
Mackenzie	0.0	1.0	1.5	1.5	1.5
Alaska	0.0	0.0	0.0	0.0	0.0
Total Supply[2]	**16.7**	**17.7**	**18.3**	**16.0**	**13.1**
Less: Western Canada Demand	4.6	5.8	6.3	6.2	5.8
Total Supply Available for Export	**12.1**	**11.9**	**12.0**	**9.8**	**7.3**
Throughput on Other Pipelines	6.9	7.1	7.1	5.9	4.7
Mainline Throughput	**5.2**	**4.8**	**4.9**	**3.9**	**2.6**

TransCanada: Low Case
(Bcf/d[1])

	2005	2010	2015	2020	2025
Supply					
Conventional	16.2	13.9	11.7	8.4	6.2
Unconventional	0.1	0.5	1.4	1.9	2.1
Net Storage	-0.11	-0.02	-0.02	0.00	0.00
Mackenzie	0.0	0.8	0.8	0.8	0.8
Alaska	0.0	0.0	0.0	0.0	0.0
Total Supply[2]	**16.3**	**15.9**	**15.0**	**12.4**	**9.9**
Less: Western Canada Demand	4.6	5.7	6.1	5.9	5.6
Total Supply Available for Export	**11.7**	**10.2**	**8.9**	**6.5**	**4.3**
Throughput on Other Pipelines	6.8	6.4	5.6	4.3	3.1
Mainline Throughput	**4.9**	**3.8**	**3.3**	**2.2**	**1.2**

TransCanada: High Case
(Bcf/d[1])

	2005	2010	2015	2020	2025
Supply					
Conventional	17.1	16.9	16.3	13.3	9.6
Unconventional	0.3	1.7	3.9	5.3	5.7
Net Storage	-0.11	-0.02	-0.02	0.00	0.00
Mackenzie	0.0	1.0	1.6	1.8	1.8
Alaska	0.0	0.0	0.0	0.0	0.0
Total Supply[2]	**17.1**	**19.0**	**20.5**	**18.7**	**15.6**
Less: Western Canada Demand	4.4	4.9	5.0	5.0	4.7
Total Supply Available for Export	**12.7**	**14.1**	**15.5**	**13.7**	**10.9**
Throughput on Other Pipelines	6.9	7.9	9.1	8.3	6.9
Mainline Throughput	**5.8**	**6.2**	**6.4**	**5.4**	**4.0**

TransCanada: Alaska-in Case
(Bcf/d[1])

	2005	2010	2015	2020	2025
Supply					
Conventional	16.6	15.5	13.8	10.7	7.4
Unconventional	0.02	1.0	2.5	3.6	3.9
Net Storage	-0.11	-0.02	-0.02	0.00	0.00
Mackenzie	0.0	1.0	1.5	1.5	1.5
Alaska	0.0	0.0	5.1	5.5	5.5
Total Supply[2]	**16.7**	**17.5**	**22.9**	**21.3**	**18.3**
Less: Western Canada Demand	4.6	5.8	6.8	7.0	6.6
Total Supply Available for Export	**12.1**	**11.7**	**16.1**	**14.3**	**11.7**
Throughput on Other Pipelines	6.9	7.0	9.8	9.0	7.8
Mainline Throughput	**5.2**	**4.7**	**6.3**	**5.3**	**3.9**

TransCanada: Distress Case
(Bcf/d[1])

	2005	2010	2015	2020	2025
Supply					
Conventional	15.8	11.6	9.8	7.8	n.a.[3]
Unconventional	0.1	0.5	1.2	1.4	n.a.
Net Storage	-0.11	-0.02	-0.02	0.00	n.a.
Mackenzie	0.0	0.8	0.8	0.8	n.a.
Alaska	0.0	0.0	0.0	0.0	n.a.
Total Supply[2]	**15.9**	**13.3**	**12.7**	**10.6**	n.a.
Less: Western Canada Demand	4.7	5.6	6.5	7.0	n.a.
Total Supply Available for Export	**11.2**	**7.7**	**6.2**	**3.6**	n.a.
Throughput on Other Pipelines	6.7	5.5	4.5	2.8	n.a.
Mainline Throughput	**4.5**	**2.2**	**1.7**	**0.8**	n.a.

CAPP: Base Case Sensitivity
(Bcf/d[1])

	2005	2010	2015	2020	2025
Supply					
Conventional	16.6	15.7	14.3	10.9	7.7
Unconventional	0.2	1.0	2.5	3.6	3.9
Net Storage	-0.11	-0.02	-0.02	0.00	0.00
Mackenzie	0.0	1.0	1.5	1.5	1.5
Alaska	0.0	0.0	0.0	0.0	0.0
Total Supply[2]	**16.7**	**17.7**	**18.3**	**16.0**	**13.1**
Less: Western Canada Demand	4.6	5.8	6.3	6.2	5.8
Total Supply Available for Export	**12.1**	**11.9**	**12.0**	**9.8**	**7.3**
Throughput on Other Pipelines	6.3	6.2	6.2	5.2	4.1
Mainline Throughput	**5.8**	**5.7**	**5.8**	**4.6**	**3.2**

CAPP: Low Case Sensitivity
(Bcf/d[1])

	2005	2010	2015	2020	2025
Supply					
Conventional	16.2	13.9	11.7	8.4	6.2
Unconventional	0.1	0.5	1.4	1.9	2.1
Net Storage	-0.11	-0.02	-0.02	0.00	0.00
Mackenzie	0.0	0.8	0.8	0.8	0.8
Alaska	0.0	0.0	0.0	0.0	0.0
Total Supply[2]	**16.3**	**15.9**	**15.0**	**12.4**	**9.9**
Less: Western Canada Demand	4.6	5.7	6.1	5.9	5.6
Total Supply Available for Export	**11.7**	**10.2**	**8.9**	**6.5**	**4.3**
Throughput on Other Pipelines	6.8	6.4	5.6	4.3	3.1
Mainline Throughput	**4.9**	**3.8**	**3.3**	**2.2**	**1.2**

CAPP: High Case Sensitivity
(Bcf/d[1])

	2005	2010	2015	2020	2025
Supply					
Conventional	17.1	16.9	16.3	13.3	9.6
Unconventional	0.3	1.7	3.9	5.3	5.7
Net Storage	-0.11	-0.02	-0.02	0.00	0.00
Mackenzie	0.0	1.0	1.6	1.8	1.8
Alaska	0.0	0.0	0.0	0.0	0.0
Total Supply[2]	**17.1**	**19.0**	**20.5**	**18.7**	**15.6**
Less: Western Canada Demand	4.4	4.9	5.0	5.0	4.7
Total Supply Available for Export	**12.7**	**14.1**	**15.5**	**13.7**	**10.9**
Throughput on Other Pipelines	6.9	7.9	9.1	8.3	6.9
Mainline Throughput	**5.8**	**6.2**	**6.4**	**5.4**	**4.0**

1 1 Bcf/d = 28.3 106 m3/d
2 Total Supply may not add up due to rounding and methodology used by TransCanada to estimate conventional and unconventional supply.
3 Not available

Appendix V

Order AO-3-TGI-07-2003

ORDER AO-3-TGI-07-2003

IN THE MATTER OF the *National Energy Board Act* and the regulations made thereunder; and

IN THE MATTER OF an application filed by TransCanada PipeLines Limited pursuant to Part IV of the Act for orders fixing and approving tolls that TransCanada shall charge for transportation services provided on its Mainline natural gas transmission system (Mainline) between 1 January 2004 and 31 December 2004; and

IN THE MATTER OF Hearing Order RH-2-2004.

BEFORE the Board on 15 April 2005

WHEREAS TransCanada filed an application dated 12 November 2003 for interim tolls for the Mainline effective 1 January 2004;

AND WHEREAS on 18 December 2003, the Board approved TransCanada's 12 November 2003 application, as amended on 3 December 2003, and issued Order TGI-07-2003;

AND WHEREAS TransCanada filed an application dated 26 January 2004 for an order fixing just and reasonable tolls that it may charge for or in respect of transportation services provided on its Mainline between 1 January 2004 and 31 December 2004 (2004 Tolls Application);

AND WHEREAS on 23 March 2004, the Board issued Hearing Order RH-2-2004 establishing a two-phase procedure to consider TransCanada's 2004 Tolls Application;

AND WHEREAS an oral public hearing was held in Ottawa, Ontario between 14 June 2004 and 25 June 2004 during which time the Board heard the evidence and argument presented by TransCanada and all interested parties with respect to RH-2-2004 Phase I matters;

AND WHEREAS on 23 July 2004, the Board issued Amending Order AO-1-TGI-07-2003 approving revised interim tolls effective 1 August 2004;

AND WHEREAS the Board's Decisions arising out of the RH-2-2004 Phase I Proceeding are set out in its Reasons for Decision dated September 2004, and in Order AO-2-TGI-07-2003;

AND WHEREAS applications for review of the RH-2-2004 Phase I Decision were filed by the Canadian Association of Petroleum Producers on 12 November 2004 and by Coral Energy Canada Inc. and the Cogenerators Alliance on 11 January 2005 (jointly, the Phase I review applications);

AND WHEREAS, an oral public hearing was held in Calgary, Alberta between 29 November 2004 and 4 February 2005 during which time the Board heard the evidence and argument presented by TransCanada and all interested parties with respect to RH-2-2004 Phase II matters;

AND WHEREAS the Board's Decisions arising out of the RH-2-2004 Phase II Proceeding are set out in these Reasons for Decision dated April 2005 and this Order.

THEREFORE, IT IS ORDERED, pursuant to Parts I and Part IV of the Act, that:

1. TransCanada shall file final tolls schedules with the Board for approval within 30 days of the later of either the release of the Phase II Decision or the Board's disposition of those aspects of the Phase I review applications that could impact the 2004 revenue requirement. The filing shall reflect the Phase II Reasons for Decision and the decisions of the Board regarding the issues from Phase I, including the following:

    a) the Mainline's rate of return on common equity shall continue to be based on the RH-2-94 Formula methodology;

    b) the Board approves an increase in the Mainline's deemed common equity ratio from 33 percent to 36 percent;

    c) the Board approves a percentage of debt in the Mainline's deemed capital structure of 64 percent;

    d) the effective date for reflecting these changes in capital structure for rate-making purposes shall be 1 January 2004; and

    e) any variance between the approved 2004 revenue requirement and the amounts collected pursuant to interim tolls shall be deferred and disposed of in future tolls.

NATIONAL ENERGY BOARD

Michel L. Mantha
Secretary

Rate of Return on Common Equity (ROE) for 2004
NEB Letter, 2004

National Energy Board
Office national de l'énergie

File 4750-A000-11
28 November 2003

BY FACSIMILE

To: Parties Named in the Attached Distribution List

Rate of Return on Common Equity (ROE) for 2004

Pursuant to the ROE adjustment mechanism approved in the Multi-Pipeline Cost of Capital Decision (RH-2-94), revised on 14 March 1997 to eliminate rounding, the Board has approved a rate of return on common equity of 9.56 percent for the year 2004.

In arriving at its decision, the Board relied upon a 10-year Government of Canada forecast bond yield of 5.15 percent (Source: November 2003 Consensus Forecasts). To this forecast, the Board added 53 basis points, which was the average actual yield differential between the 10 and 30-year Government of Canada bonds observed during the month of October 2003 (Source: National Post). The above calculation produced a forecasted 30-year Government of Canada bond yield of 5.68 percent for 2004, which is 30 basis points lower than the 5.98 percent forecasted yield relied upon in the ROE calculation for 2003. The 30 basis point yield differential between the current and previous forecasts was multiplied by 0.75, producing a downward adjustment of 23 basis points to the 2003 approved ROE of 9.79 percent. Therefore, the ROE for 2004 is 9.56 percent.

Companies are directed to serve forthwith a copy of this letter on their shippers and interested parties.

Yours truly,

Michel L. Mantha
Secretary

Attachment

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Rate of Return on Common Equity (ROE) for 2005
NEB Letter, 2005

National Energy Board
Office national de l'énergie

File 4750-A000-11
25 November 2004

By Facsimile

To: Parties Named in the Attached Distribution List

Rate of Return on Common Equity (ROE) for 2005

Pursuant to the ROE adjustment mechanism approved in the Multi-Pipeline Cost of Capital Decision (RH-2-94), revised on 14 March 1997 to eliminate rounding, the Board has approved a rate of return on common equity of 9.46 percent for the year 2005.

In arriving at its decision, the Board relied upon a 10-year Government of Canada forecast bond yield of 5.05 percent (Source: November 2004 Consensus Forecasts). To this forecast, the Board added 50 basis points, which was the average actual yield differential between the 10- and 30-year Government of Canada bonds observed during the month of October 2004 (Source: National Post). The above calculation produced a forecasted 30-year Government of Canada bond yield of 5.55 percent for 2005, which is 13 basis points lower than the 5.68 percent forecasted yield relied upon in the ROE calculation for 2004. The 13 basis point yield differential between the current and previous forecasts was multiplied by 0.75, producing a downward adjustment of 10 basis points to the 2004 approved ROE of 9.56 percent. Therefore, the ROE for 2005 is 9.46 percent.

Companies are directed to serve forthwith a copy of this letter on their shippers and interested parties.

Yours truly,

Michel L. Mantha
Secretary

Attachment

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DISTRIBUTION LIST

Board Letter dated
25 November 2004
File 4750-A000-11

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Rate of Return on Common Equity (ROE) for 2006
NEB Letter, 2006

National Energy Board
Office national de l'énergie

File 4750-A000-11
2 December 2005

BY FACSIMILE

To: Parties Named in the Attached Distribution List

Re: **Rate of Return on Common Equity (ROE) for 2006**

Pursuant to the ROE adjustment mechanism approved in the Multi-Pipeline Cost of Capital Decision (RH-2-94), revised on 14 March 1997 to eliminate rounding, the Board has approved a ROE of 8.88 percent for the year 2006.

In arriving at its decision, the Board relied upon a 10-year Government of Canada bond yield forecast of 4.55 percent (Source: November 2005 Consensus Forecasts). To this forecast, the Board added 23 basis points, which was the average actual yield differential between the 10- and 30-year Government of Canada bonds observed during the month of October 2005 (Source: National Post). The above calculation produced a forecasted 30-year Government of Canada bond yield of 4.78 percent for 2006, which is 77 basis points lower than the 5.55 percent forecasted yield relied upon in the ROE calculation for 2005. The 77 basis point yield differential between the current and previous forecasts was multiplied by 0.75, producing a downward adjustment of 58 basis points to the 2005 approved ROE of 9.46 percent. Therefore, the ROE for 2006 is 8.88 percent.

Companies are directed to serve forthwith a copy of this letter on their shippers and interested parties.

Yours truly,

Michel L. Mantha
Secretary

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Rate of Return on Common Equity (ROE) for 2007
NEB Letter, 2007

National Energy Board | Office national de l'énergie

File 4750-A000-11
23 November 2006

BY FACSIMILE

To: Parties Named in the Attached Distribution List

Rate of Return on Common Equity (ROE) for 2007

Pursuant to the ROE adjustment mechanism approved in the Multi-Pipeline Cost of Capital Decision (RH-2-94), revised on 14 March 1997 to eliminate rounding, the Board has approved a ROE of 8.46 percent for the year 2007.

In arriving at its decision, the Board relied upon a 10-year Government of Canada bond yield forecast of 4.15 percent (Source: November 2006 Consensus Forecasts). To this forecast, the Board added 7 basis points, which was the average actual yield differential between the 10- and 30-year Government of Canada bonds observed during the month of October 2006 (Source: Financial Post). The above calculation produced a forecasted 30-year Government of Canada bond yield of 4.22 percent for 2007, which is 56 basis points lower than the 4.78 percent forecasted yield relied upon in the ROE calculation for 2006. The 56 basis point yield differential between the current and previous forecasts was multiplied by 0.75, producing a downward adjustment of 42 basis points to the 2006 approved ROE of 8.88 percent. Therefore, the ROE for 2007 is 8.46 percent.

Companies are directed to serve forthwith a copy of this letter on their shippers and interested parties.

Yours truly,

Michel L. Mantha
Secretary

Attachment

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National Energy Board
Office national de l'énergie

Dossier 4750-A000-11
Le 23 novembre 2006

PAR TÉLÉCOPIEUR

Destinataires : Toutes les parties nommées dans la liste de distribution ci-jointe

Objet : **Taux de rendement du capital-actions ordinaire (RCO) fixé pour 2007**

Madame, Monsieur,

Conformément au mécanisme de rajustement du RCO approuvé dans le cadre de la décision sur le coût du capital des sociétés pipelinières (RH-2-94), et révisé le 14 mars 1997 pour éliminer l'arrondissement des chiffres, l'Office a autorisé un RCO de 8,46 % pour l'exercice 2007.

Pour le calculer, l'Office s'est fondé sur le rendement prévu de 4,15 % des obligations de 10 ans du gouvernement du Canada (selon le numéro de novembre 2006 de *Consensus Forecasts*), auquel il a ajouté 7 points de base, soit l'écart moyen entre les rendements réels des obligations de 10 ans et de 30 ans du gouvernement du Canada en octobre 2006 (selon le *Financial Post*). L'estimation du rendement des obligations à long terme (30 ans) du gouvernement du Canada est donc de 4,22 % en 2007, ce qui représente une baisse de 56 points de base par rapport au rendement prévu de 4,78 % qui a servi à calculer le RCO en 2006. L'Office a multiplié par 0,75 l'écart de 56 points de base entre la prévision actuelle et celle de l'an dernier, ce qui a abouti à un rajustement à la baisse de 42 points de base du RCO de 8,88 % autorisé pour 2006. Ainsi, le RCO de 2007 s'établit à 8,46 %.

Les sociétés sont priées de signifier immédiatement une copie de la présente lettre à leurs expéditeurs et aux parties intéressées.

Veuillez agréer, Madame, Monsieur, mes salutations distinguées.

Le secrétaire,

Michel L. Mantha

Pièce jointe

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Newfoundland Power, Inc.,
PUB Order No. P.U. 19 (2003)

Newfoundland
& Labrador
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF THE

2003 GENERAL RATE APPLICATION

FILED BY

NEWFOUNDLAND POWER INC.

DECISION AND ORDER

OF THE BOARD

ORDER No. P.U. 19 (2003)

BEFORE:

Mr. Robert Noseworthy
Chair and Chief Executive Officer

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

Mr. John William Finn, Q.C.
Commissioner

P.U. 19(2003)

IN THE MATTER OF the *Public Utilities Act* R.S.N. 1990, Chapter P-47 *(*the *"Act*");

AND IN THE MATTER OF a General Rate Application by Newfoundland Power Inc., filed pursuant to Order No. P.U. 22(2002-2003)

BEFORE:

Robert Noseworthy
Chair and Chief Executive Officer

Darlene Whalen, P.Eng.
Vice-Chair

John William Finn, Q.C.
Commissioner

DATE: June 20, 2003

TABLE OF CONTENTS

PART ONE. BACKGROUND

I. THE APPLICATION

1. Filing

Newfoundland Power (NP), pursuant to Order No. P.U. 22(2002-2003) filed an Application (the *"Application"*) with the Board of Commissioners of Public Utilities (the "Board") on October 11, 2002 for an Order or Orders of the Board approving, among other things, the proposed rates for the various customers of NP, to be effective May 1, 2003. (See Appendix A)

On February 10, 2003 NP filed an amended Application to reflect 2002 actuals along with updated economic data. (See Appendix G) The Pre-filed Evidence, Exhibits and Studies filed as part of the original application were also updated and re-filed. In addition the evidence was revised to reflect the Board's decisions respecting NP's 2003 Capital Budget as contained in Order No. P.U. 36(2002-2003) issued on December 20, 2002. In the amended Application NP proposed revised rates to be effective August 1, 2003.

2. Application Proposals

In the Application NP is proposing the Board approve the following:

1. *"accounting treatments and policies with effect from January 1, 2003 to:*
   a) *amortize the recovery over a five year period, of an amount of $5.6 million that has accumulated in the Weather Normalization Reserve;*
   b) *adopt on a prospective basis, the market-related method of valuing pension assets for the purposes of determining pension expense;*
   c) *amortize over a three year period, the estimated Board and Consumer Advocate's regulatory costs of $1.2 million incurred with respect to this Application; and*
   d) *credit one-half of the balance of $944,000 in the Excess Revenue Account to Newfoundland Power's revenues in each of 2003 and 2004 to reduce revenue requirements from rates that would otherwise be recovered from customers in those years.*

2. *provision for customer recovery of the remaining balance of the 1992 and 1993 excess earnings by reducing revenue requirement to be recovered from rates by $112,000 in 2003 and $335,000 in 2004.*

3. *calculation of depreciation expense with effect from January 1, 2003 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 3 year period an accumulated reserve variance of $17.2 million identified in the Depreciation Study filed with the Application.*

4. *rates, tolls and charges effective for service provided on and after August 1, 2003, to provide an average increase in electrical rates of 0.96 per cent, based upon:*
   a. *a forecast average rate base for 2003 of $599,245,000 and for 2004 of $622,650,000;*

   b. *a rate of return on average rate base of 10.55 per cent in the range of 10.30 to 10.80 per cent; and*

   c. *a forecast revenue requirement to be recovered from electrical rates, following implementation of the proposals set out in paragraphs 9,10 and 11 of the Application, of $378,327,000 for 2003 and $385,490,000 for 2004.*

5. *continued use of the Formula with changes to:*
   a. *adopt the method used by the National Energy Board and the British Columbia Utilities Commission to determine the risk free rate;*
   b. *use an equity risk premium of 4.75 per cent at a risk free rate of 6 per cent for 2003; and*
   c. *allow a range of return on rate base of 50 basis points.*

6. *amendments to the Rules and Regulations governing Newfoundland Power's provision of electrical service to its customers to:*
   a. *eliminate the statement preparation fee;*
   b. *reduce the fee applicable for customer name changes from $14 to $8; and*
   c. *extend the application of the reconnection fee to circumstances where customers request reconnection of service following a landlord's request for disconnection of service.*

7. *defer dealing with outstanding issues related to revenue recognition and the Unbilled Revenue Increase Reserve Account pending resolution of an outstanding dispute with the Canada Customs and Revenue Agency.*

8. *additional capital expenditures for 2003 of $425,000 to permit Newfoundland Power to undertake a load research program."*

II. THE HEARING

1. Notice and Pre-Hearing Conference

Notice of the Application and Pre-hearing Conference was published in newspapers throughout the province. The Pre-hearing Conference was held on October 30, 2002 and resulted in the Board issuing Procedural Order No. P.U. 27(2002-2003), which identified registered intervenors, set procedural rules for the conduct of the hearing, and set the schedule for the filing and service of documents, the motions days and the actual hearing. (See Appendix B)

NP was represented throughout the hearing by Ms. Gillian Butler, Q.C. and Mr. Peter Alteen, LL.B.

The registered intervenors for the hearing were the Government appointed Consumer Advocate, Mr. Dennis Browne, Q.C., represented by Mr. Stephen Fitzgerald, LL.B., and Newfoundland and Labrador Hydro (NLH), represented by Mr. Geoffrey Young, LL.B.

The Board was assisted at the hearing by Mr. Mark Kennedy, LL.B., who acted as Board Hearing Counsel; Ms. Dwanda Newman, Board Counsel; Ms. Cheryl Blundon, Board Secretary; and Ms. Barbara Thistle, Assistant Board Secretary.

2. Interim Order

On December 16, 2002, NP filed an application with the Board for an interim order extending effective January 1, 2003 the current Schedule of Rates, Tolls and Charges approved in Order No. P.U. 22(2002-2003). The rates were to remain in place pending a further Order of the Board following the hearing of the general rate application. The Board subsequently issued Order No. P.U. 35(2002-2003) approving NP's proposal. (See Appendix E)

3. Motions and Procedural Order Amendments

At the first scheduled motions day on December 4, 2002 the Board heard representations on a motion from the Consumer Advocate regarding the evidence of one of NP's proposed cost of capital experts, Ms. Kathleen McShane. The motion requested that either: a) the Board strike Ms. McShane's evidence from the record; or b) if Ms. McShane's evidence is allowed, that the cost related to Ms. McShane's evidence not be the responsibility of the ratepayers but be borne by NP's shareholders; and c) the Board provide direction to the parties as to the number of experts a party should be permitted to call on any particular issue. Following the hearing of the motion the Board issued Order No. P.U. 33 (2002-2003) denying the motion. (See Appendix C)

At the request of and with the agreement of the parties, on December 12, 2002 Procedural Order No. P.U. 34(2002-2003) was issued, amending the schedule of dates and order of witnesses. (See Appendix D)

A further motions day was held on January 10, 2003. NP filed a motion requesting amendment of the Procedural Order No. P.U. 34(2002-2003) to extend the filing date for NP's responses to information requests and to delay the start date of the hearing to March 3, 2003. After hearing the motion the Board rendered an oral decision extending the date for the filing of responses by NP to information requests but reserved its decision on NP's request to postpone the start date of the hearing. The Board subsequently issued Procedural Order No. P.U. 1(2003) which among other things amended the schedule of dates and set the start date of the hearing for March 3, 2003. (See Appendix F)

On February 17, 2003 NP filed an application with the Board objecting to certain issues as set out in the Consumer Advocate's Issues List, specifically those issues relating to the setting and fixing of a rate of return on common equity for NP. NP requested that the Board: (1) issue an Order determining that it has no jurisdiction with respect to certain issues; (2) limit consideration of related issues at the public hearing; and (3) strike those issues from the Consumer Advocate's Issues List. On February 21, 2003 the Board heard from the parties regarding the application and subsequently issued Order No. P.U. 5(2003) denying the application of NP excepting that it would not hear evidence on the setting and fixing of a rate of return on common equity to the extent that it is beyond the Board's jurisdiction. (See Appendix I)

At the hearing on February 21, 2003 Board Counsel presented for consideration a revised Rules of Procedure, as well as an order of witnesses for the hearing. There was a disagreement between NP and the Consumer Advocate concerning the Rules of Procedure, specifically the rules surrounding the calling of panels of witnesses and also the manner of presenting to witnesses documents which are not part of the hearing record. The Board, after considering the submissions of the parties issued Procedural Order No. P.U. 4(2003) which modified the rules for the conduct of the hearing and set out the order of witnesses. (See Appendix H)

During the hearing the Board also received a request from the Consumer Advocate to issue subpoenas to 5 witnesses. NP requested an opportunity to make submissions on this issue and the Board heard from the parties on April 1, 2003. As a result the Board issued Order No. P.U. 8(2003) wherein it consented to issue only one of the subpoenas requested. (See Appendix K)

4. Technical Conference/Mediation

In preparing for the hearing the Board proposed a number of days be set aside to allow for a technical conference. The purpose of the technical conference was to provide the parties with an opportunity to settle certain issues in advance of the hearing. With the assistance of a Board appointed mediator, Dr. J. W. Wilson, the parties focused on cost of service allocation, rate structure and tariff matters.

Agreement was reached on all issues set out for mediation with the exception of one item related to meter reading. The parties subsequently filed a Mediation Report with the Board detailing issues upon which settlement was reached. The parties also consented to the admission of all pre-filed testimony and exhibits of witnesses pertaining to the settled issues without the calling of witnesses for the purpose of cross-examination.

The Board considered the Mediation Report and subsequently issued Order No. P.U. 7(2003) which accepted and adopted the Mediation Report and the proposed resolution of issues upon which the parties agreed. (See Appendix J) These proposals are incorporated into this Decision. Given the parties reached no agreement on meter reading, the Board has addressed the issue in this Decision based on evidence and cross-examination during the hearing.

The Board is of the view that the technical conference/mediation proved successful and contributed to a streamlining of the regulatory process. The Board believes this kind of dialogue between the parties provided a number of advantages including reduced regulatory costs, less time spent on expert testimony during the hearing, consensus decision making and reporting. Each of these enhance the quality of regulation in the public interest as well as to the benefit of the parties and the Board. The Board expresses its sincere desire to build on this initiative at future hearings and to incorporate technical conferences/mediation as a sound business practice aimed at addressing specific regulatory issues between hearings.

The Board wishes to thank Dr. Wilson and the parties for their support and cooperation in this very worthwhile initiative.

5. The Hearing

The hearing commenced on March 3, 2003 and continued over a six-week period for 23 hearing days. Written submissions were filed on April 22, 2003 and the Board heard oral argument on April 25, 2003. The following witnesses were called by the parties and the Board:

<u>Witnesses called by NP</u>:

Mr. Philip Hughes, CA	President and CEO, NP
Mr. Barry Perry, CA	Vice-President Finance and Chief Financial Officer, NP
Mr. Ron Crane	Director of Forecasting, NP
Mr. Earl Ludlow, P. Eng.	Vice President, Engineering and Operations, NP
Dr. Roger Morin	Professor of Finance, Robinson College of Business, and Professor of Finance for Regulated Industry, Centre for the Study of Regulated Industries, Georgia State University
Ms. Kathleen McShane	Senior Consultant and Vice-President, Foster and Associates, Bethesda, Maryland
Mr. John Browne	J.T. Browne Consulting, Toronto, Ontario
Mr. John F. Weidmayer	Gannet Fleming Valuation and Rate Consultants, Inc.
Mr. Bruce Chafe	Chair of the Board, NP

Witnesses called by the Consumer Advocate:

Dr. Basil Kalymon	Professor of Finance, Richard Ivey School of Business, University of Western Ontario

Witnesses called by Board Hearing Counsel:

Mr. William R. Brushett, CA	Partner, Grant Thornton LLP, St. John's, NL (Board's Financial Consultant)

Public participation days were held in St. John's and Corner Brook. During this phase of the hearing interested persons and organizations were offered the opportunity to present their views on issues arising from the Application.

The Board heard from the following persons during the public participation days:

In St. John's on April 4, 2003:

Mr. Owen Crossan, Regency Management Ltd., St. John's, NL
Mr. Greg Malone, Private Citizen, St. John's, NL
Mr. Gary Milley, Executive Director, Newfoundland & Labrador Parks/Recreation Association, St. John's, NL
Mr. Charlie Oliver, Martek Morgan-Finch, St. John's, NL
Mr. Terry McNeil, Climate Change Action Coordinator, Conservation Corps of Newfoundland and Labrador, St. John's, NL
Ms. Sara Peckford, Climate Change Action Coordinator, Conservation Corps of Newfoundland and Labrador, St. John's, NL
Mr. Dennis O'Keefe, Chair, Consumer Group for Fair Gas Prices, St. John's, NL
Mr. Bill Rossitor, Private Citizen, Mount Pearl, NL

In Corner Brook on April 11, 2003:

Ms. Priscilla Boutcher, Mayor, City of Corner Brook, NL
Mr. Edward Buckle, Private Citizen, Corner Brook, NL
Mr. Mark Baldwin, President, Corner Brook Chamber of Commerce, Corner Brook, NL
Mr. Peter Blake, Private Citizen, Corner Brook, NL
Mr. Michael J. Griffin, Q.C., Private Citizen, Grand Falls-Windsor, NL
Mr. Walwin Blackmore, Mayor, Town of Grand Falls-Windsor, NL

The Board appreciates the time and effort of those who appeared before the Board to present their views on the Application. The presentations and comments were very helpful in providing the Board with both personal and community perspectives and the Board has considered this input in making its decisions.

Interested persons and organizations were also given the opportunity to submit a Letter of Comment, which also formed part of the record before the Board. Letters of Comment were submitted by:

Mr. Gerald Hounsell, Splash "N" Putt Cabins, Glovertown, NL
Ms. Heide Pearce, Toulon Development Corporation, St. John's, NL
Mr. Wayne Richards and Ms. Janet Richards, Regency Towers, St. John's, NL
Ms. Catharine and Mr. Graham Bailey, Port Rexton, NL
Mr. & Mrs. Gerald Hennifent, Norris Arm, NL
Ms. Judy Tilley, Torbay Estates Limited, St. John's, NL
Mr. Mark Sexton, CEO, Corner Brook Economic Development Corporation, Corner Brook, NL

The Board also extends its appreciation to those persons and organizations submitting Letters of Comment.

In addition to the sworn evidence given at the hearing, which included evidence provided at the public participation days, additional evidence was entered by way of information requests, consent filings, and information filings. The Board has considered all the evidence before it in this proceeding and will refer directly to the evidence upon which it based its findings as set out in this Decision.

III. REGULATION OF NP 1998-2002

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 220,000 residential and general service customers, or approximately 85% of all electrical consumers in the Province. Newfoundland and Labrador Hydro (*"NLH"*) serve the remainder. NP's total energy sales in 2002 were 4,765 GWh. NP purchases in excess of 90% of its energy requirements from NLH and supplies the rest itself using small hydro-electric generation.

NP's last rate review, in November 1998, was preceded by a full cost of capital hearing. Significant changes in market rates of return led to a preliminary investigation and a hearing was subsequently called by the Board in May 1998 under Section 88 of the *Act* into, *inter alia*, the matter of NP's rate of return and capital structure. The resulting Board Order No. P.U. 16(1998-99) used a maximum common equity ratio of 45% and return on equity (*"ROE"*) of 9.25% to calculate a rate of return on rate base of 9.91%, which contributed to a decrease in rates effective January 1, 1998 of 2.1%. The concept of an automatic adjustment formula to set rates in upcoming years was also considered and the utility was ordered to address this issue in a general rate application with a hearing scheduled for the fall of 1998. This application also incorporated a number of other outstanding issues, including funding of pension liability and possible excess earnings in 1992 and 1993.

Following this hearing, the Board issued Order No. P.U. 36(1998-99) in January 1999. This Order set rates for 1999 and put in place an Automatic Adjustment Formula (the *"Formula"*) to determine rates beyond the test year(s). The Formula was designed to annually adjust NP's rate of return on rate base based on changes in the forecast cost of common equity linked to changes in long-term Canada bond yields. The average weighted cost of capital was to be determined using this revised ROE and was then incorporated into the Formula on an annually adjusted basis along with the ratio of forecast average invested capital to average rate base in order to yield an allowed return on rate base and hence set rates in the following year. Additional details on the Formula are outlined on pg. 62 of this Decision. In addition to setting the Formula, Order No. P.U. 36(1998-99) also confirmed NP's maximum common equity ratio of 45% and determined for the 1999 test year a rate of return on rate base of 9.81%, based on an ROE of 9.25%. The result was a rate increase of 1% which became effective February 1, 1999.

Prior to the Board's issuing its cost of capital decision for NP in June 1998, the Court of Appeal rendered its opinion on a case stated before the Supreme Court of Newfoundland by the Board pursuant to Section 101 of the *Act*, (the *"Stated Case"*) requesting an opinion on the jurisdiction of the Board. Among other matters, the Court of Appeal provided an opinion regarding the Board's jurisdiction to:

- set and fix the level of return on common equity;
- regulate the return on rate base;
- require a public utility to maintain ratios within its capital structure; and
- deal with excess earnings of the utilities being regulated.

In addition to the matters raised during the hearing the Board's Order No. P.U. 36(1998-99) also addressed its understanding of the Court's opinion and its effect on the regulation of NP.

Application of the Formula resulted in an increase in NP's rates of 0.7% in 2000, no change for 2001, and a decrease of 0.6% for 2002.

In June 2002 the Board issued Order No. P.U. 7(2002-2003) arising from NLH's general rate application. This decision and the subsequent rate Order No. P.U. 21(2002-2003) resulted in an increase in NP's purchased power costs of 6.5%. In August 2002, NP filed an application with the Board requesting new rates in order to pass through these increased costs. The Board issued Order No. P.U. 22(2002-2003) which approved an increase of 3.68% to NP's customers. This Order fixed NP's rates until December 31, 2002 and directed NP to file a general rate application for a full review of its 2003 costs, including cost of capital, no later than October 11, 2002. The general rate application was filed as required and is the subject of this Decision and Order.

Since the effect of Order No. P.U. 22(2002-2003) was that no approved Schedule of Rates, Tolls and Charges would be in place as of January 1, 2003, NP filed an application on December 16, 2002 for an interim Order under Section 75 of the *Act*. This application requested that the existing rates remain in effect until further Order of the Board following the hearing of NP's general rate application. The Board approved this application and issued Interim Rate Order No. P.U. 35(2002-2003). Rates for 2003 will be finalized in this Decision and Order.

During the period 1998-2002, the Board also dealt with a number of additional applications from NP, including a number of routine Contribution in Aid of Construction approvals, annual approval of balances in the Weather Normalization Account and the annual approval of rate stabilization and municipal tax adjustments. The Board also held public hearings in each year from 1999-2002 to consider NP's capital budget proposals. At these capital budget hearings, the Board dealt with approval of revised amounts for rate base and invested capital for use in the Formula in determining return on rate base for the subsequent year.

Other specific decisions issued by the Board in relation to NP during this regulatory period (1998-2002) included:

- i) Order No. P.U. 24(1999-2000) – Approval of amortization and funding of pension liability associated with an early retirement program.
- ii) Order No. P.U. 37(2000-2001) – Approval of a rebate to customers of $6,733,000 plus HST credited to the Excess Revenue Account resulting from a tax reassessment.
- iii) Order No. P.U. 17(2001-2002) – Approval of NP's proposal to purchase poles jointly used with Aliant and the associated additional capital expenditures for 2003 of $22,100,000.
- iv) Order No. P.U. 23(2002-2003) – Approval of issuance of Series AJ First Mortgage Bonds up to $75,000,000 pursuant to Section 91 of the *Act*.

IV. 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) for NLH 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. This background may form a routine introduction to all future Board decisions involving a general rate application by a utility, although some variations in format and content may be evident from time to time.

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 (S.N. 1994, Chapter-E-5.1)* (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."

To date, the Board has received no direction under either provision from the Lieutenant-Governor in Council in respect of NP.

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.

All hearing documentation is 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.nf.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. The evidence can also be viewed simultaneously by the Board, parties and witnesses on monitors located in the Hearings Room.

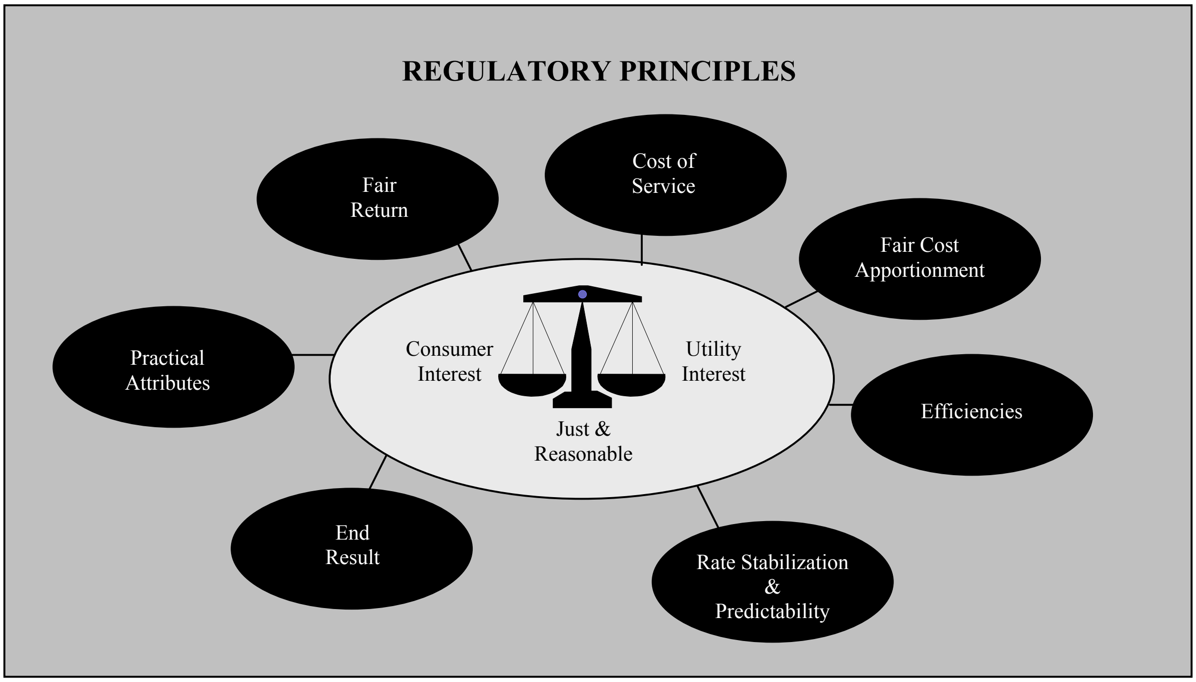
Through these procedures the Board ensures that the process is accessible and transparent for stakeholders, including the public. The Board may also travel throughout the province to hear from interested persons or organizations. Full and informed public debate and discussion on the issues is encouraged 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. Together with the Decision an 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 and are specifically outlined on pages 383-384 of his book.

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. <u>Fair Cost Apportionment</u>

Fairness of specific rates in the apportionment of total costs of service among the different ratepayers 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. <u>Efficiencies</u>

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 employed in promoting innovation and responding economically to changing demand and supply patterns.

5. <u>Rate Stability and Predictability</u>

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. <u>End Result</u>

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

7. <u>Practical Attributes</u>

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.

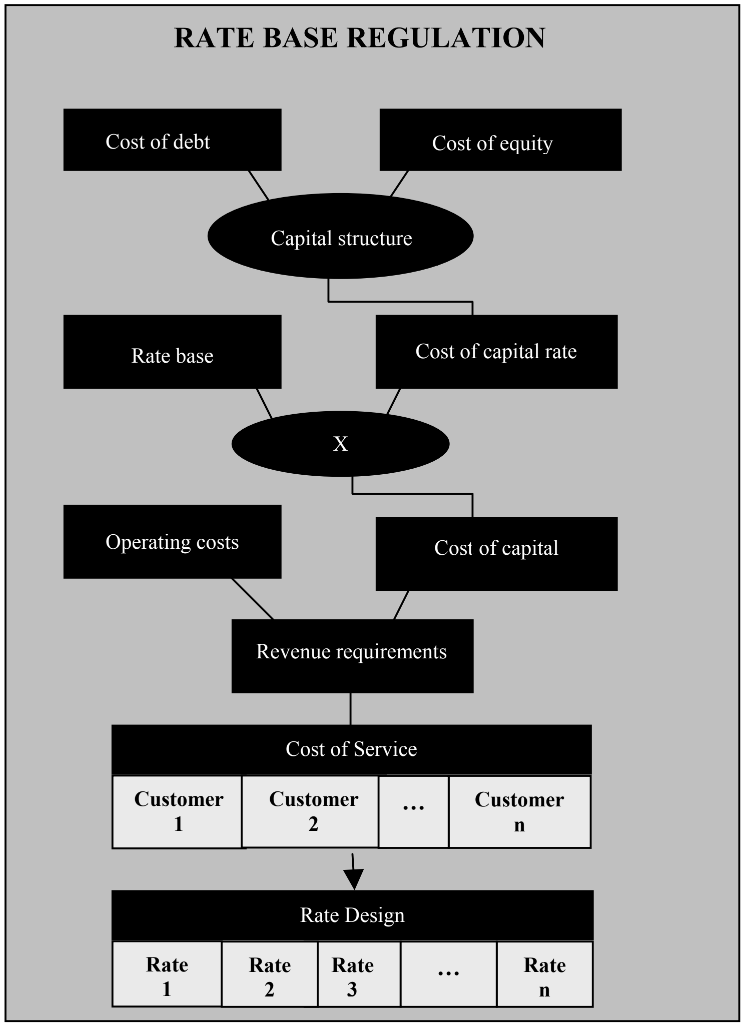
During rate proceedings the Board is often petitioned by intervenors and presenters to consider the customers' ability to pay when setting rates for various classes of customers and service. While cross subsidization of a group of customers contributing toward the cost of service assigned to another 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)
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 that 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

The Board believes 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.

PART TWO. BOARD DECISIONS

I. SUBMISSION OF CONSUMER ADVOCATE ON EXCESS EARNINGS

As part of the preliminary procedures set by the Board each party was required to file an Issues List to help focus and define the relevant issues contained in the Application. In the listing filed by the Consumer Advocate the following issues were identified, *inter alia*, as matters to be addressed during the hearing:

> *"1. Excess earnings by Newfoundland Power above the allowed Rate of Return on Equity since the implementation of the Automatic Adjustment Formula and since Board Orders in 1998 and subsequent Orders;*
>
> *2. Rebate to consumers any excess earnings resulting from Newfoundland Power's earnings above the allowed Rate of Return on Equity since the implementation of the Automatic Adjustment Formula and since Board Orders in 1998 and subsequent Orders;*
>
> 3. *A re-definition of Excess Earnings so that excess earnings will include excess earnings which are beyond the Allowed Rate of Return on rate base and include also Excess Earnings which are beyond the allowed Rate of Return on Equity."*

Arising from the submission of these issues by the Consumer Advocate, NP filed an Interlocutory Application February 17, 2003, which sought an Order of the Board, *inter alia*, as follows:

> *"(a) pursuant to Section 11 of the Regulations, directing that insofar as the issues raised on the Consumer Advocate's Issues List are premised upon the Board possessing jurisdiction to:*
>
> *(i) set and fix the return that Newfoundland Power may earn on equity, or*
>
> (ii) *determine the existence of excess revenues other than on the basis of Newfoundland Power's return on rate base,*
>
> *those issues shall not be considered at the public hearing of the Application.*
>
> *(b) pursuant to Section 26 of the Regulations, directing an amendment of the Consumer Advocate's Issues List to strike out those matters contained in the Consumer Advocate's Issues List that are premised upon the Board processing jurisdiction to:*
>
> *(i) set and fix the return that Newfoundland Power may earn on equity, or*
>
> (ii) *determine the existence of excess revenues other than on the basis of Newfoundland Power's return on rate base."*

The application was heard before the Board on February 21, 2003 following which the Board issued Order No. P.U. 5(2003), which declined to strike any issue from the Consumer Advocate's list. The Board, however, confirmed that it would not hear evidence or submissions on the issue of the setting and fixing of the rate of return that NP may earn on equity to the extent that it is beyond the jurisdiction of the Board. The Board did not rule on whether it has the jurisdiction to determine excess earnings on any basis other than NP's return on rate base.

This issue was raised during the hearing by the Consumer Advocate in cross-examination of both Mr. Hughes and Mr. Perry, and also in final written submission and oral argument. In final submission (pg. 16) the Consumer Advocate stated that NP has earned more than $13 million over and above what the Board intended. In this respect NP earned an ROE greater than the 9.25% ROE used by the Board to set NP's return on rate base in Order No. P.U. 36(1998-99). The Consumer Advocate argued that no authority is found within the Stated Case to allow NP to retain these excess earnings. The Consumer Advocate further argued that the Board has jurisdiction to define excess revenue for the purposes of the operation of the Excess Revenue Account provided that definition meets the requirements as stated by the Court of Appeal. In support of his position the Consumer Advocate referenced the opinion of Justice Green as set out in paragraphs 111-114 of the Stated Case. The Consumer Advocate concluded:

> "*Based on the foregoing, it is clear that the Board had jurisdiction to define excess revenue for the purposes of maintenance of a reserve account by incorporating in the definition the maximum level of return on common equity."* (Final Submission, Consumer Advocate, pg. 18)

The Consumer Advocate further stated on page 19 of his final submission:

> *"If the Board had jurisdiction to define excess revenue for the purposes of the establishment of the excess revenue account by reference to a level of return on common equity, then the Board has jurisdiction to retroactively revise a previous Order for the purpose of correctly stating the definition of excess revenue."*

The Consumer Advocate requested the Board order these excess earnings to be either returned to consumers or treated similar to the disposition of excess earnings in Order No. P.U. 36(1998–99). (Final Submission, Consumer Advocate, pg. 22) In oral argument the Consumer Advocate further suggested that, if the Board was not prepared to rule on this issue, the matter could be referred back to the Court of Appeal for further clarification. Pending resolution of the issue, the Consumer Advocate requested that the Board consider whether or not NP should be required to segregate such earnings into an interest bearing account. (Transcript, April 25, 2003, pgs. 117-118)

NP disagreed with the Consumer Advocate's position and dealt with the issue extensively in its written submission. NP argues the Board's jurisdiction on this issue is limited as follows (Section G, pg. 17):

> *"From a legal perspective NP submits that the Stated Case clearly indicates that the Board's jurisdiction to regulate a public utility's returns is limited to regulation of the return on rate base. This limitation was specifically indicated by the Court of Appeal to apply to the determination of excess revenues. While the Court of Appeal did refer in the Stated Case to the Board's ability to define a "reserve account" by reference to returns on equity, it specifically provided that the Board could not in so defining an account deprive a public utility of a level of return on rate base to which the Board had determined the utility to be entitled under s.80(1) of the Act. In fact, the Stated Case explicitly indicated how excess earnings were to be determined."*

NP's position is that only where a utility's return on rate base exceeds the upper limit of the rate of return on rate base as prescribed by the Board does the Board have jurisdiction over the disposition of those earnings. (Transcript, April 25, 2003, pg. 52)

NP also raised concerns about the Consumer Advocate's suggestion that the Board has the *"jurisdiction to retroactively revise a previous order"* to allow a rebate to customers. NP submitted that this would amount to retroactive regulation, stating that:

> *"Finally, on the issue of regulation of excess revenues, the Board has issued a series of orders specifically defining and redefining Newfoundland Power's Excess Revenue Account. Insofar as the issues raised in this proceeding constitute revisiting those orders, they raise serious issues of retroactive regulation that are contrary to both law and sound public utility practice."* (Written Submissions, NP, Section G, pg. 18)

NLH did not address the issue of NP's excess earnings in either written submissions or oral argument, though it did participate in the initial motion of the Consumer Advocate.

The Court of Appeal, in para. 57 of the Stated Case, specifically addressed the impact of any calculations by the Board of a rate of return on common equity, stating:

> *"Subsection 80(1) makes no reference at all to determining, let alone setting and fixing, the rate of return on common equity. The calculation of an appropriate rate of return on common equity is truly a mere component in the overall process of determining a just and reasonable return on rate base".*

The above comment of Justice Green was central to his conclusions outlined in para. 61 of the Stated Case where he states:

> *"I therefore conclude that the power to determine a just and reasonable return on rate base, as contained in section 80(1) of the Act, does not include within it a power to set and fix a rate of return on common equity, but it obviously does contemplate that the analysis would be undertaken and factored into the conclusion as to what is a just and reasonable return on rate base."*

This conclusion is confirmed by Justice Green, where in para. 109, he states:

> *"In light of the answer given to Question 1, the benchmark for determining excess revenue is the range of return on rate base determined by the Board to be just and reasonable".*

The Board concluded it is appropriate and necessary that the Board consider the cost of common equity in deriving a just and reasonable return on rate base. It is the Board's view that the Stated Case confirms that the *Act* does not confer upon the Board a jurisdiction to fix and determine the returns of NP other than with reference to the utility's rate base. The cost of common equity is merely an input into the determination of a just and reasonable return.

The suggestion of the Consumer Advocate that the Board require NP to rebate to consumers any *"excess earnings above the allowed Rate of Return"* since 1998 requires that the

Board have the jurisdiction to first determine that there are excess earnings in relation to the return on equity and also that the Board has the jurisdiction to dispose of those excess earnings.

The following key paragraphs in the Stated Case guide the Board in making its final determination on the issues raised by the Consumer Advocate:

"111. As a result of the discussions at the hearing, however, it is apparent that there is a more fundamental issue at stake. The assumption appears to be that if the Board chooses to define excess revenue for the purpose of establishment of the excess revenue account in terms of revenue earned in excess of the maximum return on common equity, it is in effect saying that revenue earned below that maximum but which happens to be in excess of the just and reasonable return on rate base as determined by the Board under s-s. 80(1) is necessarily money which the utility can keep. This position is obvious from the arguments made by counsel for NLP since his position has been throughout that excess revenue has no meaning other than by reference to the definition used for the purposes of the excess revenue account. As indicated previously[78], this is not a correct interpretation of the situation. The same assumption is also apparent from the position taken by the Consumer Advocate who argues that the decision of the Board to define excess revenue for the purpose of the excess revenue account in terms of exceeding the return on common equity, as opposed to rate base is ultra vires the Board because the Board must determine excess revenue by reference to revenues which are earned in excess of a just and reasonable return on rate base.

112. The assumption that the definition of excess revenue for the purpose of the operation of the reserve account is equivalent to the concept of excess revenue flowing from earnings in excess of a just and reasonable return on rate base as prescribed under s-s. 80-1, is false. I agree with the Consumer Advocate, for reasons already given[79], that any revenues earned in excess of the maximum range of a just and reasonable return on rate base are revenues to which the utility is not automatically entitled. It does not follow, however, that for the purposes of regulating the accounts of the utility, the Board is prevented from requiring payment into an excess revenue account on a different basis (provided it does not deprive the utility of the level of return on rate base to which it has been determined to be entitled). The Board can and should deal with all revenue earned in excess of a just and reasonable return on rate base; however, it does not have to require that all of it be paid into an excess revenue account.

113. As indicated in the answers to Questions 3 and 4, the Board has a broad jurisdiction as to how to deal with the excess and it may well be that, in the circumstances obtaining, it will determine that only a portion (i.e. that portion above the maximum return on common equity) should be paid into a reserve account. It might determine that the rest should be rebated to consumers or used by the utility in furtherance of the objective of ensuring that it maintains a sound credit rating in the financial markets of the world. In short, there is nothing wrong in principle with the Board defining excess revenue for the purposes of a reserve account differently from the notion of excess revenue as determined by a comparison with a just and reasonable return on rate base as determined by s-s. 80(1). In so doing, however, the Board ought not to assume that any additional excess revenue ought necessarily to be returned to the utility to be used as it sees fit. The Board

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[78] para. [73]

[79] paras. [31], [50]

has jurisdiction, and in exercise of its legislative mandate it ought to exercise that jurisdiction, to make a determination as to how that remaining excess revenue, if any, should be dealt with consistent with the objectives and policies of the legislation.

114 Accordingly, the technical answer to Question 5 is "no" but so as to limit any confusion over the implications of the wording of the question, I would add that the Board has jurisdiction to define excess revenue for the purposes of maintenance of a reserve account by reference to the maximum level of return on common equity (or any other appropriate measure for that matter) but that does not mean that the Board may for all purposes define the level of excess revenue to which the utility is not entitled by reference to that measure; rather, the Board must determine, on the specific circumstances of the case, what is to be done with respect to any excess revenue measured against a just and reasonable return on rate base. If all or a portion of the excess revenue, measured against the return on rate base, is not ordered to be paid into a reserve account, it must nevertheless be dealt with in some other manner consistent with the objects and policies of the legislation. It should not be simply assumed that such excess revenue if not required to be paid into a reserve account belongs to the utility to be dealt with as it sees fit."

In para. 114 the Board's jurisdiction to define excess revenue for the purposes of maintenance of a reserve account by reference to the maximum level of return on common equity is in the context of determining what earnings must be paid into a reserve account or, in the alternate, what funds not paid into a reserve account may be otherwise appropriately disposed of by the Board. However, the Court of Appeal is clear in para. 112 that any definition of excess earnings is subject to the ultimate proviso that the utility can not be deprived of the level of return on rate base which was allowed.

The Board finds that the Consumer Advocate is incorrectly equating measures which the Court has indicated are appropriate to the Board for purpose of defining and establishing a reserve account with measures which the Board may use to determine the existence of excess earnings to which NP is not entitled. The Consumer Advocate does not distinguish whether or not the measure encroaches upon earnings to which the utility is entitled as of right; in particular, earnings which are within the range of the return on rate base as ordered by the Board but may be in excess of the component rate of return on equity.

Following the rendering of the majority opinion in the Stated Case, through Order Nos. P.U. 36(1998-99) and P.U. 37(1998-99), the Board effectively revised the definition of the Excess Revenue Account such that the account to this date has been maintained with reference to the upper limit of the allowed range of return on rate base as set and fixed by the Board. This change for purpose of maintenance of this account was a recognition by the Board that, while it could continue to maintain an excess earnings account with reference to the rate of return on common equity, it appears to be of little practical consequence to do so when the only jurisdiction the Board has to dispose of these earnings is when they exceed the range of return on rate base.

The Board therefore concludes that the only jurisdiction it can exercise is over excess earnings which exceed the allowed range of return on rate base as set by the Board. In respect of these earnings the Board can order that they be utilized for the benefit of ratepayers in a manner the Board deems appropriate and in accordance with the objectives and policies of the legislation. The Board in future will continue to exercise its discretion in this manner to the benefit of ratepayers, specifically as set forth in Order Nos. P.U. 36(1998-99) and P.U. 37(2000-2001), but it cannot go further and exceed its jurisdiction by depriving NP of earnings to which it is otherwise entitled under the *Act.*

The Board finds that it has no jurisdiction under the *Act* to require payment by NP into a reserve account or otherwise deprive NP of any amount which is within the allowed return on rate base as fixed and determined by the Board pursuant to Section 80(1) of the *Act.*

II. FORECASTING ISSUES

Mr. Ron Crane, NP's Director of Forecasting, provided evidence on NP's customer and energy sales forecasts for 2003 and 2004. These forecasts form the basis of the test year projections for both revenue from electrical sales and for purchased power expense, NP's largest single expenditure. Exhibit BVP-27 (1st Revision) provides details on NP's customer and energy sales forecasts, along with the economic and financial assumptions used.

1. Economic Assumptions

The economic assumptions used by NP in preparing the customer and energy sales forecasts are based on the Conference Board of Canada's *Provincial Outlook, Long Term Forecast 2003 Edition*, dated December 6, 2002. According to Mr. Crane, Gross Domestic Product (GDP) is forecast to grow by 3.2% in 2003 and 1.5% in 2004. In 2003 the economy will benefit significantly from the development of both the White Rose and Voisey's Bay projects and continued increases in oil production. This compares to an average annual growth in excess of 5% since 1997, largely as a result of large resource based projects such as Hibernia and Terra Nova. The low growth in 2004 reflects a deceleration in oil production from 2003 levels and a decline in construction expenditure. The fishing industry is forecast to grow modestly over the forecast period with landings expected to increase marginally. As a result, the goods-producing sector is forecast to grow by 4.1% in 2003 and 0.9% in 2004. [Exhibit BVP-27, (1st Revision), pg. 5] The Conference Board of Canada's *Provincial Outlook, Winter 2003*, February 24, 2003 revised the GDP forecast for the goods producing sector to show an increase of 8.9% for 2003 and a decrease for 2004 of 1.5%. (U #17)

NP's electrical energy sales growth is primarily influenced by growth in the service sector of the economy as opposed to GDP. More specifically, changes in employment levels, personal income, energy prices and population demographics in NP's service territory are more determinative of sales growth than resource industry production levels. The service sector is expected to grow by 2.7% in 2003 and 1.8% in 2004. [Exhibit BVP-27, (1st Revision), pg. 5] Economic growth will not be uniform across NP's service territory. In the Northeast Avalon, growth will continue to be robust principally due to the offshore oil industry. With the exception of the impact of the development of the White Rose Project on the Burin area, much of rural Newfoundland is expected to continue the trend of economic stagnation.

2. Customer Growth and Energy Sales Forecast

Domestic customer growth is largely influenced by the number of housing starts in each year. Mr. Crane states that, even though 2001 and 2002 have shown significant improvements in housing starts, this level is not sustainable with the demographic changes occurring in the province. The Conference Board of Canada forecasts housing starts of 1,695 units in 2003 and 1,493 in 2004. Based on this projection the number of domestic customers is forecast to grow by 0.9% in 2003 and 0.8% in 2004. [Exhibit BVP-27, (1st Revision), pg. 7]

Average domestic electricity consumption is forecast to increase by 0.7% in 2003 and remain at that level in 2004. The combined impact of customer growth and changes in average electricity use will result in growth in the volume of domestic energy sales under proposed rates of 1.6% in 2003 and 0.8% in 2004. [Exhibit BVP-27, (1st Revision) pg. 7]

The number of General Service customers is forecast to grow by 0.5% in 2003 and 2004. Under proposed rates the volume of General Service energy sales is forecast to grow by 2.2% in 2003 and 2.4% in 2004. The increased level of growth in the General Service forecast reflects activity related to construction for the White Rose project at Marystown which started in the fourth quarter of 2002. [Exhibit BVP-27, (1st Revision), pg. 8]

In Street and Area lighting class the number of customers is forecast to grow on average by 0.5% during 2003-2004, while the volume of energy sales is forecast to grow on average by 0.1%. [Exhibit BVP-27, (1st Revision), pg. 8]

Exhibit BVP-27 (1st Revision)**,** (pg. 11 of 13) shows the customer and energy sales forecasts for the 2003 to 2004 period under both existing and proposed rates. Under both scenarios the number of customers is forecast to increase by 0.8% in 2003 and 0.7% in 2004. Energy sales under existing rates are forecast to increase by 1.8% in 2003 and 1.5% in 2004. Energy sales under proposed rates are forecast to increase by 1.8% in 2003 and 1.4% in 2004. NP has incorporated the impact of elasticity into its energy sales forecast as required by Order No. P.U. 7(1996-97).

3. Forecasting Accuracy

During the hearing and in written submissions the Consumer Advocate raised the issue of NP's forecasting accuracy and the impact on revenue of *"under forecasting"* of energy sales in any given year. The Consumer Advocate argued that *"there is a disincentive for NP to accurately forecast its energy sales since if NP receives more revenue than anticipated in its forecast in any one year, NP suffers no consequence unless and until these revenues cause NP to overearn on its rate base."* (Final Submission, Consumer Advocate, pg. 14)

The Consumer Advocate has taken specific issue with NP's forecast of housing starts, stating that this input has been understated by NP in its forecasting for 2003.

In U #18 NP prepared an analysis of the effects on the forecast of energy sales of the different housing forecasts that were put before the Board during the hearing, as well as the effect of the negotiated settlement. The results of this analysis show an overall variance of approximately 0.1% on energy sales for the scenarios considered. Mr. Crane also testified that a new forecast incorporating recent events in the Province such as the flood in Badger, the potential closure of the cod fishery, and the recent announcements of a paper mill shut down would indicate approximately the same, or perhaps slightly lower, energy sales than the forecast contained in Exhibit BVP-27 (1st Revision). (Transcript, March 18, 2003, pg. 56/5; pg. 57/9)

The Consumer Advocate submitted that *"NP's growth in sales volume from year to year should be more closely monitored on an annual basis, since in 2001 and 2002 NP's forecasting has been significantly inaccurate…"* (Final Submission, Consumer Advocate, pg. 15)

Grant Thornton also reviewed NP's forecasting methodology and reasonableness of assumptions and raised no concerns. (Grant Thornton Report-NP-2003 GRA, pgs. 33-34)

A comparison of forecast energy sales to weather adjusted actual sales shows a variance of –0.4% for 1999, which is the test year used by the Board in NP's 1998 GRA hearing. Overall variances for the period 1992 to 2003 range from –2.9% in 1992 to +2.4% in 2002, with over half the variances being less than 0.5%. The Board is satisfied these variances are indicative of very good forecasting accuracy. The Board also notes that the forecasting methodology is continually tested against actual observed data using *"back casting"* techniques to ensure that the methodology remains sound. (Transcript, March 18, 2003, pg. 92/3; pg. 94/12)

The Board agrees with the Consumer Advocate that NP's growth in sales volume from year to year should be monitored. In Order No. P.U. 36(1998-99) the Board made the following Order:

> *"2(g) The Board will continue its practice of undertaking annual reviews of the company expenses and other financial and operating information of interest to the Board. Factors such as growth and sales volume will be monitored and a hearing will be convened by the Board on its own motion to consider revision in the company's revenue requirement if there is reason to believe that the adjustment mechanism has led or would lead to a level of earnings above what the Board believes to be just and reasonable."*

Since the 1998 hearing the Board has monitored growth and energy sales volumes through quarterly regulatory reports from NP and as part of its annual financial reviews. The Board has not found it necessary to make any adjustments to the forecasts for growth and energy sales as presented for the test year 1999 and upon which existing rates are based.

The Board will accept NP's customer and energy sales forecasts for the test year period 2003-2004.

III. RISK ASSESSMENT

An assessment of risks including business, regulatory and financial risks is a key determinant in NP's ability to maintain and achieve the financial targets and objectives contained in its application. The Board has assessed the evidence pertaining to each of these risks in setting NP's appropriate capital structure and return on equity (ROE) for ratemaking purposes.

1. Defining Risks

During the hearing, the Board heard a considerable amount of evidence regarding the exposure of NP to varying risks. These risks were described using a number of terms including business risk, regulatory risk, financial risk, investment risk and general utility risk without necessarily a clear evidentiary distinction being made when referring to these differing types of risk. For example, in its oral argument NP stated: *"Without exception, all three cost of capital experts agree that overall Newfoundland Power's business risks have not changed materially since 1998, and Newfoundland Power is of average business risk overall."* (Transcript, April 25, 2003, pg.22/15-20) Consistent with this position, NP cited evidentiary references from the three cost of capital experts in stating *"All experts agreed that Newfoundland Power has an approximately average utility risk."* (Written Submissions, NP, Section C, pg. 10/9-12)

Two of these references, Ms. McShane and Dr. Morin, referred to investment risk as opposed to business risk with Dr. Morin actually following up the specific reference to investment risk with the fact that NP's business risk actually exceeds that of other utilities. The third reference by Dr. Kalymon includes business risk along with capital structure risk and overall volatility in arriving at his conclusion on NP's risk profile.

Because of the lack of clarity, the Board feels compelled to distinguish between these various risks before attempting to assess them. With this in mind, the Board found Dr. Morin's pre-filed evidence helpful [Pre-filed Evidence, Dr. R.A. Morin, pgs. 18-25] along with definitions of Drs. Winters and Waters in 1998. [P.U. 16(1998-99), pgs. 20-21] The latter is particularly appropriate since it was the relative risks in each category comparing the current evidence with that of 1998 which became a primary focus of experts during the hearing. Described below are an explanation of the relevant definitions for each category of risk to be explored by the Board.

Dr. Morin	Drs. Winters and Waters (1998)
Business Risk	
Refers to the relative variability of operating profits induced by the external forces of demand for and supply of the firm's products, by the presence of fixed costs, by the extent of diversification or lack thereof of services, and by the character of regulation.	The basic risk that the utility's operating income may not be sufficient to service all its obligations, including the provision of the return on equity the investor regards as fair and expects to receive, in one or more future periods.
Regulatory Risk	
Normally included with business risk and refers to the quality and consistency of regulation applied to a given utility and to the fairness and reasonableness of regulatory decisions.	Similarly included with business risk as the risk that rates will not be set at a level sufficient to provide a fair rate or return on total capital invested.
Financial Risk	
Refers to the additional variability of earnings induced by the employment of fixed cost financing, that is, debt and capital stock.	Risks that arise through the corporation's financing and capital structure.

The Board feels the above definitions are consistent and reasonable. The Board accepts these definitions and sees no particular conflict in terms of the evidence presented during the hearing.

2. Business Risk

NP started the hearing by indicating that its overall business risks were relatively high compared to other Canadian electric and gas utilities. This is borne out in CA-599 and Mr. Perry's evidence. [Pre-filed Evidence, B.V. Perry, (1st Revision) pg. 24/21-22] In oral argument, however, NP concluded: *"Without exception, all three cost of capital experts agree that overall Newfoundland Power's business risks have not changed materially since 1998, and Newfoundland Power is of average business risk overall".* (Transcript, April 25, 2003, pg. 22/15-19)

As noted earlier, while this is not strictly accurate in terms of the evidence before the Board, there was a good deal of consensus around this particular issue. Ms. McShane testified there have been no material changes in NP's business risk profile since 1998. [Pre-filed Evidence, Ms. K. McShane, pg. 4/22-23] While noting NP operates in a highly favourable regulatory environment, Dr. Kalymon concurred in his overall assessment that the business risks of NP have not changed substantially since the last hearing. Dr. Kalymon qualified this by observing NP's business risk may now indeed be lower than certain other Canadian utilities but, at most, is comparable to the average levels for regulated Canadian companies. (Pre-filed Evidence, Dr. B. Kalymon, pg.11/19-20; pg. 12/15-19). Dr. Morin indicated that business risk for NP is principally forecasting risk and following a review of several related factors concluded that NP's business risks exceeded that of other utilities. [Pre-filed Evidence, Dr. R. Morin, pg. 22/11-12]

In addition, the Board was presented with evidence on factors influencing business risk including economic forecasts, demographic trends, regulation, competitive forces and various cost considerations highlighted by NP. Based on the level of consensus reached on this issue the Board will not belabour the evidence on these factors but will comment generally on each.

In the short to medium term aligning itself closest with the period covered by this application, the Conference Board of Canada is projecting strong economic performance in the Province though at a decelerating rate. This projection is mitigated somewhat by continuing out-migration, particularly affecting rural areas. The Board acknowledges that an aging demographic profile coupled with proportionately higher population losses in rural areas will continue to have a negative impact on NP's business risk in the longer term.

Unlike some other provincial jurisdictions, there is no evidence before the Board to suggest the regulatory environment in this Province will change. Those experts commenting on regulatory risk viewed the quality and consistency of the Board's decisions in a positive light with Dr. Morin rating the risk as slightly above average by Canadian standards. Dr. Morin attributed this to the company's low allowed ROE for 2002 and structural deficiencies in the automatic adjustment formula. (Pre-filed Evidence, Dr. R. Morin, pg. 23/26-30)

During the hearing, a regulatory caution was raised in relation to Standard and Poors' (*"S & P's"*) research report dated March 5, 2003, indicating Canadian utility regulation would be reassessed in terms of a credit rating factor. This reassessment stems from S & P's concerns regarding the reliability of the generally positive influence of regulatory factors, particularly business risk, used in its analysis of Canadian utilities. S & P plans to seek the views of Canadian regulators.

The Board acknowledges S & P's intention to reassess Canadian utility regulation as a credit rating factor but believes it is premature to speculate on the outcome of this review and even more inappropriate to apply such speculation to the decisions affecting this Order. The Board will, however, be cognizant of the relevant issues in making its decisions and it does note some recent prospectives that reflect positively on the regulatory environment affecting NP in the Province. S & P's October, 2002 research report granting an *"A"* rating to NP C$75,000,000 first mortgage bonds offered the following observation:

> *"Newfoundland Power's relatively low business risk profile is supported by cost of service/rate of return regulation; the ability to flow through all power costs; a weather normalization mechanism; and no exposure to cyclical industrial customers, which are serviced directly by the provincial government-owned utility, Newfoundland and Labrador Hydro."*

Also, the Dominion Bond Rating Service (DBRS) in its January 31, 2003 report ranks the regulation of NP as a strength in its credit rating considerations.

The competitive prospects facing NP remain relatively stable. CA-601 reveals NP will continue to face competition from traditional sources such as furnace oil, propane and wood with the degree of competition dependent on the relative economics between electricity and competitive fuels. In CA-602, while noting the spectre of the Electricity Policy Review, NP responds it possesses no specific evidence that its role in the provision of electricity will be challenged by competition in the next five years.

With a view to the arguments presented by Mr. Perry on fixed and variable costs as well as interest rates [Pre-filed Evidence, B.V. Perry, (1st Revision), pgs. 22-24], the Board is not persuaded that either of these items will significantly affect the business risk of NP.

Following this assessment, the Board agrees that the business risk profile of NP has not changed appreciably since 1998.

The Board does not anticipate a change in the business risk of NP in the foreseeable future and concurs with the assessment of NP and the cost of capital experts that NP is of average business risk compared to other utilities.

3. Financial Risk

i) Market Conditions

Fluctuating conditions in the capital markets were presented by NP as an important consideration in contributing to its cost of capital. NP pointed to the changes which have occurred in the capital markets since 1998; in particular, the spread between the company's first mortgage bonds and long-term Canada bond yields. These spreads have trended from 68 basis point in 1996 to 130 in November 1998 to 185 in October 2002. In 2002, the spread between NP's bonds and long-term Canada bonds was 2.7 times greater than in 1996. This increased volatility, NP argued, contributed to greater risk and a higher cost of capital, affecting both the rate at which NP can borrow and the return to which its investors are entitled. (Written Submissions, NP, pg. 10/14-26; pg. 11/1-15; Transcript, April 25, 2003, pg. 25/1-10).

Ms. McShane described numerous factors which have contributed to changes in both the bond and equity markets since 1998. A combination of investors scurrying to safer government securities combined with decreased government borrowing has resulted in thin markets, especially for 30-year maturities. A negative spread which existed between 10-year and 30-year Canada bond yields has corrected itself. Canadian corporate bonds, however, have maintained a normal positive yield slope. Ms. McShane suggests the growing spreads between utility bonds and long term Canadas can be traced to a number of events since 1998 – a scarcity premium related to decreased government borrowing, flights to quality investments in the face of the global market crisis of 1998, and the subsequent crisis of confidence in corporate America, as well as a widespread economic downturn from which global recovery is not yet assured, particularly in the U.S. In terms of the equity market, Ms. McShane reviewed multiple factors which, in her judgement, warrant expanding the Board's analysis of the market risk premium beyond historic Canadian risk premiums and more in line with the U.S. equity markets. In an exhibit duplicated below, Ms. McShane shows the deterioration in relative average allowed

ROEs between Canadian and U.S. utilities along with a corresponding widening gap in risk premiums while observing average long-term government bond yields have remained similar. (Pre-filed Evidence, Ms. K. McShane, pgs. 23-36)

Year	Average Allowed ROE Canadian Utilities	Average 30-Year Canada Yield	Risk Premium	Average Allowed ROE U.S. Utilities	Average 30-Year/Long Term Treasury Yield	Risk Premium
1994	11.6%	8.7%	2.9%	11.3%	7.4%	4.0%
1995	12.1%	8.4%	3.7%	11.5%	6.9%	4.6%
1996	11.4%	7.8%	3.6%	11.3%	6.7%	4.6%
1997	10.9%	6.7%	4.2%	11.3%	6.6%	4.8%
1998	10.3%	5.6%	4.7%	11.6%	5.5%	6.0%
1999	9.5%	5.7%	3.8%	10.7%	5.9%	4.8%
2000	9.8%	5.7%	4.1%	11.4%	5.9%	5.5%
2001	9.6%	5.8%	3.9%	11.0%	5.5%	5.6%
2002	9.5 %	5.8%	3.7 %	11.2%	5.7%	5.5%

This evidence, Ms. McShane concluded, calls into question the validity of the current levels of allowed returns as determined by automatic adjustment formulas, which were first introduced in Canada in 1994. (Pre-filed Evidence, Ms. K. McShane, pgs. 15-38)

In his assessment of market conditions, Dr. Kalymon pointed to budgetary surpluses, particularly citing the Government of Canada, as providing major relief to borrowing pressure on the capital markets, resulting in lower yield expectations by investors. Long-term bond rates can be seen as relatively stable and parallel the development of more stable and low levels of inflation in the economy. Dr. Kalymon further indicated equity markets have been exceptionally volatile in the past two years. After double digit gains from 1996 through to 2000, investor confidence has been shaken in 2001 and 2002 with significant declines in price/earnings ratios, overall returns and dividend yields. Dr. Kalymon concluded volatility has led to investor expectations reflecting low inflation levels and lower effective inflation risk premiums. (Pre-filed Evidence, Dr. B. Kalymon, pgs. 6-9)

The Board believes that, while experts agreed that substantive changes have occurred in the capital markets since 1998, they presented contradictory interpretations as to how these changes may impact NP's cost of capital. NP relied on market volatility as being central to its argument for a higher ROE. Dr. Kalymon explained that, when economic conditions and market conditions change, especially under volatile circumstances, one has to be very careful in interpreting the results of various tests to determine the cost of capital. (Transcript, March 26, 2003, pg. 19/11-15)

The Board concurs that dramatic changes have occurred in the capital markets since 1998. This market volatility has impacted cost of capital in a number of ways. The Board agrees that expectations of equity investors have been dampened in recent years by events occurring in the capital markets and this has resulted in moderating the historic levels of ROEs. This trend is reflected in Ms. McShane's evidence where allowed average ROEs for Canadian utilities have declined from 11.6% in 1994 to 10.3% in 1998 and 9.5% in 2002. In addition, as demonstrated by NP's October, 2002 bond issue, spreads between corporate borrowing and long-term government bonds are widening to reflect market volatility and the higher risk associated with corporate bonds. This gap is wider still in relation to the equity market, reflecting the even higher risk associated with equity investments.

Apart from the more universal impacts on the capital markets arising from volatile market conditions, there was no evidence presented to the Board which would signify any greater financial risk to NP than other comparable Canadian utilities resulting from these same conditions.

The Board finds that capital market conditions, in particular affecting the equity market, have changed substantially since 1998. This volatility has contributed to an overall reduction in investor expectations in the equity market from historic levels. In addition, volatility has contributed to greater spreads being demanded by corporate bondholders and equity investors to account for added risk as compared to long-term government securities. The Board finds these trends will similarly influence NP but present no greater financial risk to NP than will be experienced by other comparable Canadian utilities.

ii) Creditworthiness & Credit Rating

The *EPCA* mandates that rates charged by NP provide sufficient revenue to enable the company to earn a just and reasonable return, as provided in the *Act*, in order for it to achieve and maintain a sound credit rating in the financial markets of the world.

Along with an assessment of business risk, the creditworthiness and ultimately the credit rating of an enterprise is determined following a thorough evaluation by the various credit rating agencies of the company's financial performance while paying particular attention to its capital structure.

In reviewing NP's corporate performance for the period 1994 to 2004, Mr. Hughes highlighted a number of factors impacting financial performance. [Pre-filed Evidence, P. Hughes, (1st Revision), pg. 3/6-12] These include:

- Gross operating expenses are forecast to decrease by approximately 9% on a historical basis (23% inflation adjusted);
- The workforce is forecast to decrease by approximately 25%;
- The number of customers served is forecast to increase by approximately 9%; and
- The volume of energy sales is forecast to increase by approximately 13%.

In reviewing NP's actual financial results for 1998-2002, [Exhibit BVP-1, (1st Revision); EAL-2, (1st Revision); Grant Thornton Report-NP 2003 GRA] the Board noted the following:

- Energy sales have increased from $333,000,000 to $363,000,000, an increase of 9.0%;
- Other revenue accumulated during this period amounted to $28,000,000, primarily derived from pole attachment sources;
- Total assets have grown from $586,000,000 to $705,000,000, an increase of 20.3%, primarily attributable to upgrading and replacement of property, plant and equipment; and the purchase of joint use poles;
- Gross operating expenditures remained relatively stable over the period with 1998 at $55,400,000 and 2001 at $55,100,000 and showing a 4.2% decrease in 2002 to $52,800,000. Grant Thornton attributes this to savings in early retirement allowances ($963,000), deferred regulatory costs for the 1998 hearing ($384,000), other operating expenses including travel, tools/clothing and computing equipment/ software offset by increased insurance costs (net $960,000); and
- Net income increased from $22,200,000 to $29,400,000, an increase of 32.4%.

As shown below, the average capital structure for NP denoting relative proportions of debt and equity remained relatively stable for the period 1998-2002 with interest coverage increasing from 2.41x to 2.61x. [Exhibit BVP-1, (1st Revision), pg. 12]

Regulated Average Capital Structure		
	1998	**2002**
Debt	53.80%	54.63%
Preferred Equity	1.88%	1.54%
Common Equity	44.32%	43.83%
Interest Coverage (x-times)	2.41 x	2.61 x

According to NP, it is this improved interest coverage resulting from increased revenue from extraordinary events, primarily the tax reassessment and the Aliant pole purchase, that contributed to S & P's reinstatement in 2001 of NP's first mortgage bonds to an *"A"* rating. (Written Submissions, NP, Section C, pg. 34/11-15)

With the exception of the period 1998-2001, NP has been historically able to sustain an *"A"* credit rating on its first mortgage bonds. In its October 16, 2002 Report, S & P assigned an *"A"* rating to NP's C$75,000,000 first mortgage bonds issued at that time. In January 31, 2003, DBRS released its credit rating report confirming its long standing *"A"* rating for NP's first mortgage bonds. DBRS concluded for a regulated utility NP's financial profile is relatively strong with low leverage and favourable coverage ratios.

No cost of capital expert disputed the current creditworthiness or credit rating associated with NP. Ms. McShane noted the cost of debt to be borne by NP's ratepayers reflects a single "A" credit rating and there has been no impact to date resulting from S & P's announcements referred to earlier. (Supplementary Evidence, Ms. K. McShane, pg. 2/15-24) Dr. Morin indicated that relative to other Canadian utilities, NP's financial risks remain below average. (Pre-filed Evidence, Dr. R. Morin, pg. 25/3-4) Dr. Kalymon provided a comparative analysis of NP's bond rating with other utilities and concluded the financial viability of NP is well established based on both the credit ratings assigned the company and its demonstrated ability to access capital markets. Dr. Kalymon further observed that this is accomplished despite the smaller size and riskier market within which NP operates and indicates several other utilities operate with a lower credit rating. (Pre-filed Evidence, Dr. B. Kalymon, pg. 16/21-24)

The Board believes that the financial integrity and performance of NP is sound. Both the management and employees of NP can take pride in this accomplishment. This achievement is acknowledged by the credit rating agencies and is demonstrated by the continuing success of NP in accessing the capital markets. The Board will explore in the following section the issue of the credit linkage involving Fortis and NP and its potential impact on NP's future creditworthiness.

The Board finds that based on its financial performance NP continues to sustain a sound credit rating which is providing appropriate and cost efficient access to the financial markets.

iii) S & P's Credit Linkage NP to Fortis

Considerable evidence was heard throughout the hearing regarding the relationship between Fortis, the parent company, and NP, its subsidiary, and the impact or effect of this relationship on the regulated entity NP. The evidence referred to inter-corporate transactions, reciprocal staffing arrangements, linkage of credit ratings, financial cross-subsidization, and comparisons of financial targets including capital structure. These issues are dealt with in this Decision, on pgs. 55-61. The purpose of this assessment is to review the potential impact on NP's financial risk of S & P's credit linkage between NP and Fortis.

The comparative credit ratings between Fortis and NP summarized from evidence are as follows:

Credit Rating	Fortis	NP
Bonds	BBB (S&P) BBB+ (DBRS)	A (S&P) A (DBRS)
Corporate	A- (S&P)	A- (S&P)

During the hearing considerable attention was focused on information contained in two S & P research reports.

S & P's October 16, 2002 publication stated:

"Although Newfoundland Power's key debt-related ratios are expected to remain relatively stable, with a debt-to-capital ratio of about 55% and funds from operations (FFO) to interest coverage in the 2.8 times (x) to 3.0x range, it is the consolidated financial profile of Fortis that will influence ratings actions on Newfoundland Power in the future. Fortis' financial profile has remained relatively stable over the past six years with consolidated debt to capital in the 60%-65% range and FFO to interest coverage in the 2.25x-2.50x range. Nevertheless, key financial ratios are presently outside the acceptable range for the current rating and consolidated business risk profile.

Future ratings actions on Newfoundland Power will be directly determined by ratings actions on Fortis. The negative outlook on Fortis reflects a financial profile that inadequately supports the company's growing business risk and the current ratings. The ratings outcome on Fortis is expected to be resolved within the next year as part of Standard and Poor's ongoing assessment of global utility ratings criteria in light of some uniquely Canadian characteristics, including low deemed equity allowances and comparatively low ROEs that largely dictate a Canadian utility's financial profile. Nevertheless, adverse ratings actions are highly likely if there is no reduction in Fortis' consolidated business risk or improvement in key debt-related ratios."

The March 5, 2003 research report explained S & P would meet with Canadian regulators among others as part of its planned assessment. The report also listed Fortis as one of several Canadian companies S & P has placed on negative credit watch pending the outcome of this review. S & P noted selective downgrades in credit ratings may result from amongst this list based on the assessment, but some or all of the ratings could indeed remain unchanged.

NP indicated this linkage by S & P of parent and subsidiary is new and NP, like other utilities who are impacted, is seeking clarification from S & P in order to assess the implications. NP emphasized the other credit rating agencies (DBRS and Moody's) continue to treat NP as a stand-alone utility. (Transcript, March 7, 2003, pg. 40/8-19)

In written submissions, NP distinguishes, correctly in the Board's judgement, between the two separate issues raised in S & P's research reports. These include: (1) the assessment of Canadian utility regulators as a rating factor; and (2) the credit linkage between Fortis and NP. On the first issue, as outlined when dealing with the question of NP's regulatory risk, the Board believes it is premature to speculate on the outcome of this review in making decisions affecting this Order. With respect to the second issue, NP points out that Fortis is not subject to regulation and its capital structure requirements are based upon different considerations and will not mirror NP's. Fortis' debt is unsecured and non-recoverable to the assets of NP. It is these assets that allow NP to fulfil its obligation to serve its customers and serves as security for NP's outstanding long-term debt. The long-term debt is comprised entirely of first mortgage bonds which are rated *"A"* by both DBRS and S & P and ratepayers benefit from this rating. NP confirmed the uncertainty surrounding S & P's ratings and pronouncements but concluded a weakening of NP's balance sheet resulting from the Board's decisions would only increase the current level of risk. (Written Submissions, NP, Section C, pgs. 35-40)

Both Dr. Morin and Ms. McShane echoed support for NP's position, stating the Board should continue to evaluate the utility on a stand-alone basis in consideration of its *"A"* first mortgage bond rating. (Supplementary Evidence, Dr. Morin, pg. 3 and Ms. McShane, pgs. 2-4)

Dr. Kalymon referred to S & P's notice suggesting that the high leverage of Fortis is potentially damaging to the credit rating of NP and may cost ratepayers money. Dr. Kalymon suggests that, if NP was so concerned about coverage ratios, appropriate adjustments could be started at the parent (Fortis). Dr. Kalymon argues this only adds to the justification to revisit NP's capital structure and ROE consistent with his recommendations. (Transcript, March 27, 2003, pgs. 55/18-25; 56/1-9)

Following a review of a number of financial indicators comparing NP and Fortis, the Consumer Advocate submitted that the consequences of this relationship, insofar as it impacts on the Board's assessment of NP's allowed ROE or capital structure, should be borne solely by NP and not its ratepayers. (Final Submission, Consumer Advocate, pgs. 49-54)

Board Hearing Counsel observed it is reasonable to conclude that, if Fortis' corporate rating is lowered and by linkage NP's, there will be pressure placed on the debt ratings of NP as well. Using some examples, Board Hearing Counsel suggested the subsidiary can mitigate the potential impact of any *"linkage"* by maintaining operational and financial distance from the parent, referred to in the ratings industry as *"ring fencing"*. Conversely, closely integrated subsidiaries are more exposed to the risk of their parents; the more the parent and affiliate share resources and personnel, the greater the risk the subsidiary will lose its financial independence and status as a stand-alone utility. In any event, Board Hearing Counsel concludes the linkage between Fortis and NP is a significant and potentially troubling change in the ratings game with implications for how NP is to be regulated in the future. (Final Brief, Board Hearing Counsel, pg. 9/9-25)

The Board takes particular note that, for the first time in NP's history, a link has been made by a credit rating agency (S & P) assigning it the same corporate credit rating as Fortis, which has now been placed on a negative credit watch, citing the parent's unacceptable financial ratios. The Board agrees the outcome of this review by S & P remains uncertain but could conceivably result in a downgrade to NP's corporate rating and in turn affect its *"A"* bond rating. A downgrade in its bond rating will translate into higher debt costs to NP and potentially higher rates to its customers, a situation the utility has stridently argued against throughout the course of the hearing. This prospect is unacceptable and the Board will require NP to take all steps possible to mitigate against this outcome.

The Board acknowledges that its jurisdiction over the relationship between NP and Fortis is limited to regulating NP. The Board's responsibility is to set fair and reasonable financial targets for NP while ensuring least cost electricity to consumers. As reflected on pg. 46 of this Decision the Board has concurred with NP's proposal to maintain a capital structure of 45% common equity. Despite this decision taken by the Board to preserve a bond rating compatible with least cost electricity, NP could potentially experience a lower bond rating resulting in higher incremental costs for electricity by virtue of its association with its parent Fortis. The Board believes this condition is not in the interest of either consumers or the utility. The Board recognizes this situation is not a reality at this time but such an outcome presents a distinct and troubling consequence. The Board is not prepared to simply presume a stand-alone utility in the future and has an obligation to ensure the financial integrity and independence of NP is fully protected on behalf of those it serves.

The Board concludes that in the interest of both the utility and its customers. NP should continue to be treated as a stand-alone utility. Therefore, the Board will require NP to take all appropriate steps necessary to preserve the financial integrity and independence of the utility. As a first step, NP will be required to file a report by June 30, 2004 addressing how it can ensure stand-alone status in respect of its corporate credit linkage by S & P to Fortis. This report should: 1) document discussions with the credit rating

agencies and Fortis on this issue; 2) explain how other regulated Canadian utilities are facing similar challenges; 3) provide a list of possible mitigating actions; and 4) provide a plan of implementation of recommended actions.

4. Summary of Risks

The Board concurs with the consensus among the experts in finding that the business risks associated with NP were average compared to other Canadian utilities. The regulatory risk of NP is subject to the review proposed by S & P to determine the quality of regulation as a credit ratings factor. The Board points to evidence indicating a generally positive regulatory environment in which NP operates. The Board concludes it is inappropriate to speculate on the outcome of this review by S & P in its decisions relating to this Order.

As demonstrated by NP's most recent bond issue (October 2002) the utility has been able to maintain a sound credit rating and cost efficient access to the financial markets. The financial performance and capital structure of NP is quite favourable relative to other Canadian utilities. Market conditions, while particularly volatile in the equity market, are not viewed by the Board to have any greater impact on the financial risk of NP in comparison to other utilities.

While experts agreed NP's current financial risk was below average, respective positions were complicated by other related issues. In this respect, the Board expresses serious concerns regarding S & P's pronouncements linking the credit rating of NP with that of Fortis, which has been placed on negative credit watch by S & P. The Board has directed NP to take all steps necessary to protect its status as a stand-alone utility and so preserve its financial integrity and independence.

With a view to overall investment risk, Dr. Morin concluded the net result of his medley of risk factors is that NP possesses average total investment risk to possibly slightly above average. (Pre-filed Evidence, Dr. R. Morin, pg. 25/8-9) Ms. McShane indicates that, with a common equity ratio close to 45%, NP would be viewed by investors as approximately average investment risk relative to the spectrum of investor-owned electric and gas-utilities in Canada. (Pre-filed Evidence, Ms. K. McShane, pg.11/11-13) Based on his assessment of business risk, capital structure risk and volatility risk, Dr. Kalymon observed that NP would be considered by investors to be, at most, comparable in risk to the average regulated utility company in Canada. (Pre-filed Evidence, Dr. B. Kalymon, pg. 16/8-10). NP concurred with the three experts in concluding it had an approximately average utility risk. (Written Submissions, NP, Section C, pg.10/9)

Despite the change in circumstances since 1998, the Board finds that the overall investment risk of NP is average when compared to other Canadian utilities. This finding will be the basis on which the Board will consider a commensurate capital structure and ROE for the utility.

IV. FINANCIAL TARGETS AND OBJECTIVES

1. Introduction

The Board acknowledges the fundamental distinction between the challenges faced by management in managing the capital structure and ROE of a utility and the Board's responsibility in balancing the interests of both the utility and consumers. Before examining the evidence relating to the capital structure of NP, the Board believes it would prove useful to the process to examine this distinction more closely.

i) Management Perspective

The challenge of the company's management is to maintain an efficient capital structure which will seek to balance the risks and costs associated with each source of funds, both debt and equity, in an effort to secure least cost capital. Given that debt is generally less risky than equity and hence is available at lower cost, in practice this management challenge reduces to establishing financial parameters, including a capital structure, that when managed in concert with the various business, regulatory and financial risks facing the company will ensure its creditworthiness in the financial markets so as to attract least cost debt. On the other hand, common shareholders are a company's primary risk takers because they receive a return on their investment only after payment of interest on bonds and other debt and dividends on preferred stock. For a regulated enterprise, the fundamental challenge for management concerning return on equity is to maximize the company's net income or earnings in order to provide the highest return possible to the shareholder within the rules laid down by the regulator. The realization of this challenge will in turn provide a stream of dividends and/or enhanced share value to the shareholder which will attract future investment as required.

ii) Board Perspective

Prior to 1996, the Board accepted capital structure objectives of NP believed necessary to maintain the company's *"A"* rating. During its 1996 general rate application, however, NP proposed modifications to its capital structure which were not supported in the Board's resulting order. This situation in part prompted the Stated Case referral whereby the Supreme Court of Newfoundland, Court of Appeal, provided an opinion regarding the Board's jurisdiction in a number of areas, including whether the Board can require a public utility to maintain ratios within its capital structure.

The Stated Case describes the process of establishing rates of return on each component of capital structure and the rate of return on rate base. In para. 28, Mr. Justice Green states:

> *"The costs associated with long term debt and preference shares are generally static over the period covered by a particular rate hearing. Accordingly, they are often described as 'embedded costs'. The rate of return necessary to be earned on rate base to cover the cost of debt and preference shares can therefore usually be easily determined based on the interest rates or dividend rates applicable to such instruments. In the case of common equity, however, the cost of the utility of this source of funds depends upon a number of factors, especially current market conditions which, by nature, can be volatile."*

In para 56, Mr. Justice Green continues:

"All of these considerations favour an approach that, in principle, should limit the degree of intrusion by the Board into the managerial control by the utility over financial decision-making. As emphasized earlier the powers of the Board should be generally regulatory and corrective, not managerial."

In para 57, Mr. Justice Green concludes:

"An alternative to actual intrusion into the utility's financial affairs in the form of a direction as to how the enterprise should be structured is for the regulator, <u>for the purpose of setting rates,</u> to base its estimates of the cost of capital on a hypothetical appropriate capital structure, thereby disregarding the utility's actual capitalization."

It is clear the Board's role is not to second-guess management on its financial decisions regarding the utility's actual capitalization. The Board's approach, however, will be to consider an appropriate capital structure upon which to estimate the cost of capital for ratemaking purposes. The Board used this approach in its 1998 hearing and will consistently follow this methodology in this Decision and Order. Clearly management has the prerogative to set a capital structure different from that ordered by the Board.

A fair ROE will be calculated by the Board, based primarily on a review of the various methodological tests and other evidence presented by the cost of capital experts.

iii) Relationship between Capital Structure, Return on Equity and Interest Coverage

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.

The relationship between capital structure, return on equity and interest coverage is a key element in any cost of capital determination.

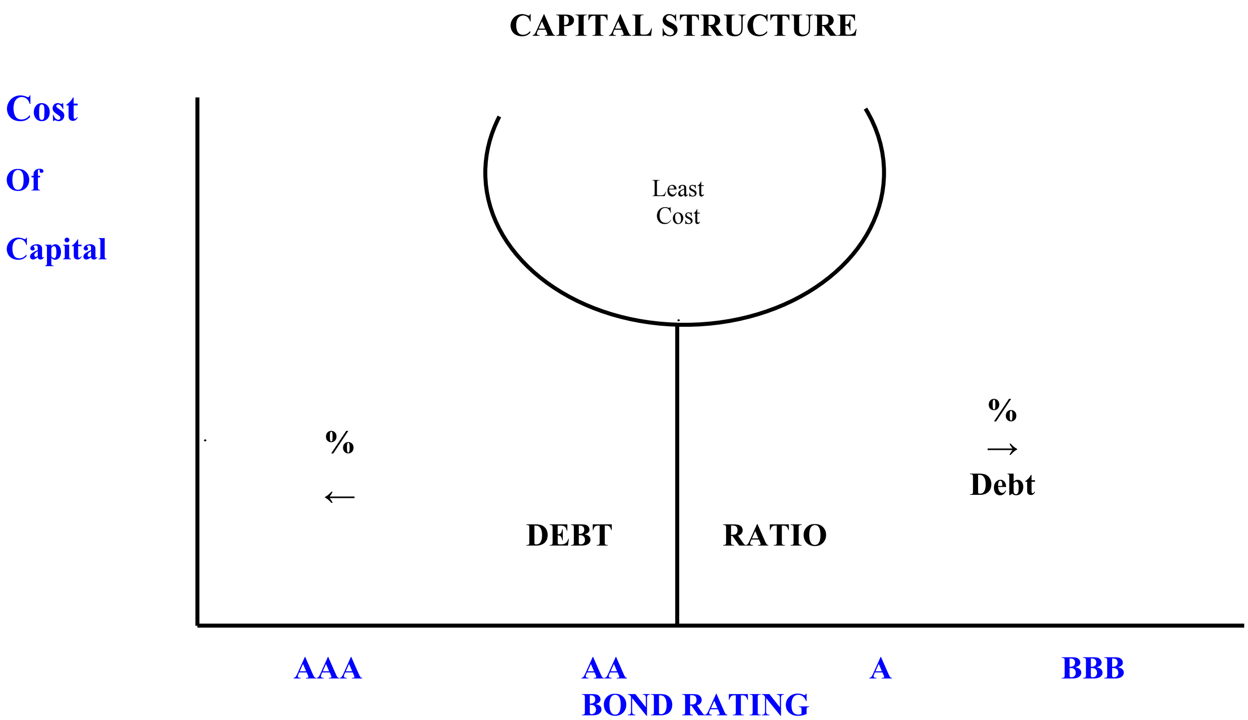
Interest coverage represents the ability of a company to meet its debt obligations and is derived as a ratio of earnings before interest and taxes to annual interest charges. Interest coverage is a prime ratio used by credit rating agencies in measuring the creditworthiness of a company since it reflects both the earnings capacity of the company and how well its capital structure or indebtedness is managed.

Return on equity (ROE) is a ratio of a company's net income or earnings (less any preferred dividends paid) to the shareholders' common stock equity or investment. ROE essentially is the measure of earnings available to common shareholders compared to their investment.

Exhibit BVP-6 (2nd Revision) demonstrates the sensitivity in the relationship between capital structure, return on equity and interest coverage. As debt increases and hence, common equity decreases combined with a decreasing ROE (all elements potentially reflecting higher risk), the interest coverage and creditworthiness of the company decreases. Higher ROEs, less debt and more common equity translates into a higher interest coverage and improved creditworthiness.

Dr. Morin explained all these things are circularly or logically linked together in a balanced system. The ROE will determine a company's profitability and interest coverage on its interest charge. The level of debt or common equity will determine how much interest a company will have to cover and that will influence ROE because lower common equity and higher risk means higher ROE. (Transcript, March 24, 2003, pg. 5/20)

The following illustration presented by Dr. Morin (Exhibit RAM-11, pg. 7) proved a useful conceptual model for the Board:



The horizontal axis displays the quality or bond rating along with the capital structure or debt to equity ratio. Moving in the direction AAA - AA - A - BBB signifies deteriorating bond ratings and increasing proportions of debt to equity. With regard to the curve, as the weight of debt increases the cost of capital reduces because of the increased use of low cost, tax deductible capital. As debt continues to increase, however, the benefit associated with low cost, tax deductible capital is more than offset by the rising cost of equity or return demanded by the investor and by the debt holder to assume the higher levels of risk associated with this increased debt. The U-shape function delineates the least cost capital structure reflecting the optimal trade-off between risk on the one hand and return on the other. The Board acknowledges the cost of capital experts may disagree on where this function falls on the horizontal axis.

2. Capital Structure

A summary of the historical and proposed capital structure of NP is as follows: [P.U. 16(1998-99), pg. 45 and CA-200, Attachment A (1st Revision), pgs. 5-6]

Capital Structure Historical and Proposed			
Order No.	**Debt**	**Preferred Equity**	**Common Equity**
P.U. 1(1990)	45-50%	6-9%	42-47%
P.U. 6(1991)	45-50%	5-10%	40-45%
P.U. 7(1996-97)	47-55%	3-6%	40-45%[1]
P.U. 16(1998-99)	Average for test year until adjusted by Board	Average for test year	< 45%[2]
Year			
2002 (actual)	54.63%	1.54%	43.83%
2003 (proposed)	54.28%	1.45%	44.27%
2004 (proposed)	54.06%	1.39%	44.55%

For the purpose of setting electricity rates, NP has proposed a forecast regulated average capital structure composed of 44.27% common equity in 2003 and 44.55% common equity in 2004.

NP referenced prior decisions of the Board in support of its position and notes the current capital structure has been maintained through appropriately managing dividend payouts to its shareholder. NP referred to Ms. McShane's evidence describing NP as a relatively small, stand alone utility which requires more conservative capital structures than larger utilities (i.e. a larger common equity ratio) in order to achieve an equivalent credit rating. NP further recited Ms. McShane's evidence indicating that the financial guidelines established by S & P for an *"A"* rated company with business risk similar to NP requires common equity 47.0 - 52.5% placing NP at the lower end of the compatible range. NP concluded that, since it has experienced no material change in risk since 1998, there is little reason to reduce the protection accorded to debt holders. (Written Submissions, NP, Section C, pg. 5 12-14)

Dr. Morin indicated he has always been supportive of the past attitude displayed by the Board regarding capital structure. He stated in respect of a possible meeting between the Board and S & P over its regulatory concerns: *"just tell our story, there we have the highest common equity ratio in Canada here. We have first mortgage bonds here, unlike any other utility in Canada."* Dr. Morin suggested, however, now is not the time to weaken NP's capital structure. (Transcript March 24, 2003, pgs. 86/8-10; 88/2-8).

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1 Common equity exceeding 45% deemed preferred with ROE of 6.33% assigned for rate setting.
2 For purposes of setting rates through the automatic adjustment formula, lesser of 45% or projected average common equity in test year.
ROE of 6.33% applied to preferred equity as well as common equity > 45%.

Dr. Kalymon on the other hand observed high levels of equity imply expensive costs of capital and this is very relevant to customers of the utility because lowering the cost of capital means lowering their rates. Dr. Kalymon also pointed out that Fortis is clearly functioning with leverage structures that are substantially higher than NP and it is troublesome that consumers cannot enjoy the same efficiency that a more leveraged capital structure would imply. Dr. Kalymon concluded from his analysis that the capital structure risk of NP is well below that of comparable Canadian utilities and recommends a reduction in the common equity ratio to 40% which still places NP at the top end for regulated utilities in Canada. Dr. Kalymon suggested the differential between the approved 45% and the 40% could be substituted with preferred shares as a desirable way to hold interest coverage. (Transcript, March 26, 2003, pgs. 17/14-17; 18/1-14; Pre-filed Evidence, Dr. B. Kalymon, pgs. 13-15)

The Consumer Advocate supported the recommendations of Dr. Kalymon indicating a fairer capital structure for NP should be adopted and implemented by the Board. (Final Submission, Consumer Advocate, pg. 51)

Board Hearing Counsel explained that, as a consequence of both double leverage financing at the parent corporate level and substantial debt financing of its non-utility enterprises, Fortis' consolidated capital structure has more debt and less equity (and, therefore is correspondingly riskier) than the capital structure NP recommends for ratemaking purposes in this application. Board Hearing Counsel noted the argument of the Consumer Advocate that maintaining an *"A"* rating in view of Fortis' own choice of a much thinner consolidated common equity ratio may be both futile and exceedingly costly to NP's ratepayers, especially if little or no additional long-term bond financing is required by NP in the near future. (Final Brief, Board Hearing Counsel, pgs. 14-15)

The capital structure of NP has been maintained through the ongoing decisions of the Board as contained in its respective Orders and also NP's actions in managing the level of common equity accordingly. Generally in the past it has been determined by the Board that a strong equity component is needed to mitigate the impact of NP's relatively small size and low growth potential. The Board reiterates its earlier finding that NP has an average business risk which incorporates these elements into this assessment. The Board also notes that NP retained an *"A"* credit rating in its October 2002 bond issue with an actual capital structure of 44% equity despite having an ROE characterized by NP as the lowest in Canada. Based on this recent experience and the Board's findings relating to NP's risk profile, the Board is not convinced at this time to change what has proven a sound and successful capital structure for NP. The Board is not satisfied that the common equity component could be notably reduced without significantly compromising interest coverage. Dr. Kalymon's proposal to substitute preferred shares for equity is not seen as an acceptable solution in the judgement of the Board. The Board notes this same proposal by Dr. Kalymon was rejected in Order No. P.U. 16(1998-99). In reaching this decision of a maximum 45% common equity component, the Board recognizes NP will continue to retain one of the most favourable capital structures among Canadian utilities of comparable risk. The Board acknowledges the sensitivity in the relationship between capital structure and ROE and the importance of maintaining an appropriate balance to ensure both efficient access to the capital markets by NP and least cost electricity for consumers. The challenge for the Board now is to set an appropriate ROE which will preserve this necessary balance.

Having reviewed the evidence the Board is of the opinion that it is reasonable and prudent to maintain the capital structure deemed appropriate in Order No. P.U. 16(1998-99). The proportion of regulated common equity in the capital structure should not exceed 45%. Any regulated common equity in excess of 45% will only be entitled to a rate of return equal to the rate of return on preferred equity. For the purpose of determining the weighted average cost of capital (WACC), the Board accepts NP's proposed forecast average capital structure for the 2003 and 2004 test years.

3. Return on Equity (ROE)

NP has proposed that the Board allow a return on regulated common equity of 10.75% for ratemaking purposes. This ROE compares to 9.25% found by the Board in 1998, and 9.05% which is currently in place based on the Formula.

i) ROE Tests

The three standard methodological tests for determining ROE were applied by the experts in varying ways. The three tests can be generally described as follows:

- Equity Risk Premium Test - A forward looking test which measures ROE in terms of a risk-free rate, normally determined in relation to government guaranteed long-term bond yields plus a premium to reflect the added risk associated with investing in the common equity of an enterprise. The Capital Asset Pricing Model (CAPM) is a variation of this test weighted more toward measuring the market price of risk to account for such factors as interest rate change and economic growth.

- Discounted Cash Flow (DCF) Test – Measures ROE in terms of the present value of projected returns to the investor, both dividends and expected growth, discounted at an appropriate rate to reflect the risk associated with these returns.

- Comparable Earnings Test - Measures ROE in relation to the past earnings of comparable companies which are then used as a proxy for future returns of the utility being considered.

ii) Application of Tests

The following summary highlights the evidence of each expert witness in applying these cost of equity tests.

Summary of Expert Evidence of Cost of Equity

Ms. McShane (@ 45% Common Equity)

Test	Description of Evidence	Rate %
Equity Risk Premium		10.5-11.25%
(i) Risk-Free Rate	• 30 year yield based on Consensus Forecasts using 10-year Canadas plus spread (est.) to account for yield differential.	• 6.0%
(ii) Risk Premium	• 3 tests conducted (incl. CAPM). Results (1) 4.0% @ beta 0.60-0.65%, (2) 4.75-5.0%; and (3) 4.6% - Updated 4.7%. • Canadian and U.S. data used *"Bare bones"* cost of equity (i) + (ii)	• 4.0-4.75%
(iii) Total ERP (iv) Other	• Add 50 basis points to reflect financing costs associated with other risk variables.	• 10.0-10.75% • 0.5%
Discounted Cash Flow		11.5%
(i) DCF Rate	• 2 DCF tests conducted with Results (1) 11.0 - 11.1% & (2) 11.1%. - Updated 11.5%. • U.S. data used as proxy for NP.	• 11.0%
(ii) Other	• Add 50 basis points for financing cost as above.	• 0.5%
Comparable Earnings		12.75-13.25%
	• 2 tests conducted using (1) Canadian industrials and (2) U.S. low risk industrials with emphasis on (1). Results as follows: (1) 12.75-13.25% and (2) 14%.	
Recommended ROE		**11.5–11.75%**

Dr. Morin (@ 45% Common Equity)

Test	Description of Evidence	Rate %
Equity Risk Premium		**10.5-11.0%**
(i) Risk-Free Rate (ii) Risk Premium	• Same as Ms. McShane above. • 6 studies conducted (incl. CAPM) @ beta 0.67%. Results ranging from 4.4% - 6.1% and average 5.1%. • Studies involve 2 aggregate stock market, 2 utilities and 2 regulators allowed risk premiums. • Primarily U.S. data weighted toward Canada.	• 6.0% • 4.5 – 5.0%
Discounted Cash Flow		10.5 – 11.0%
	• DCF used only to confirm ERP Results	
Recommended ROE		**10.5–11.0%**

Dr. Kalymon (@ 40% Common Equity)

Test	Description of Evidence	Rate %
Equity Risk Premium		**7.54–8.04%**
(i) Risk-Free Rate	• Spot bond yields for 10-year Canadas on December 17, 2002 coinciding with the date of his pre-filed evidence submission.	• 5.04%
(ii) Risk Premium	• For 1981-2001 negative risk premium of equities on TSX index. Incompatible with risk theory. Reversed to positive by removing capital gains on 10 year Canada. Real rate of bond interest adjusted upward to reflect increased risk of average company on TSX.	• 2.5 – 3.0%
Discounted Cash Flow		7.10–9.85%
	• Alternative DCF based on growth in dividend yield and earnings/book value. • 2 tests conducted. Results (1) utility 7.10 – 8.60% and (2) industrials 8.41 – 9.85%.	
Comparable Earnings		7.72–9.84%
	• 2 tests conducted with adjustments for market to book ratios Results (1) industrials 7.72-8.82% and utilities 7.93 – 9.84%.	
Recommended ROE		**8.5– 9.0%**

iii) Reliance on Tests

In Order No. P.U. 16(1998-99), the Board relied principally on the equity risk premium in establishing the appropriate return on regulated common equity and ordered its use in the Formula.

All three cost of capital experts presented evidence on the equity risk premium test.

Ms. McShane completed all three tests, including the DCF and comparable earnings tests and assigned some weight to each test in making her recommendation. (Pre-filed Evidence, Ms. K. McShane, pg. 64/18-20)

Dr. Morin concentrated primarily on the equity risk premium test while using the DCF test only in support of his equity risk premium recommendation. Dr. Morin noted in his evidence the DCF and comparable earnings methodologies are particularly difficult to implement in practice when you are dealing with the fast-changing and fluid circumstances of the Canadian utility industry and the scarcity of reliable capital market data on comparable companies. In addition, Dr. Morin pointed to other conceptual and methodological difficulties in applying the comparable earnings method. (Pre-filed Evidence, Dr. R. Morin, pg. 14/23-26; pg. 17/13-28)

Dr. Kalymon conducted all three tests while applying variations to the traditional DCF and comparable earnings tests. Dr. Kalymon observed the outcomes of different tests provide a wide range of results reflecting extreme volatility in the general equity markets in recent years. For this reason and given the experience of stable bond yields, Dr. Kalymon placed greater reliance on the equity risk premium test and the results of the utility sample in presenting his ROE recommendation. (Pre-filed Evidence, Dr. B. Kalymon, pg. 41/24-25; pg. 42/1-6) Dr. Kalymon did indicate, however, that other test results lead to an upward push to his primary equity risk premium outcomes in reaching his recommended ROE. (Transcript, March 26, 2003, pg. 159/1-15)

The equity risk premium test received primary weighting by the expert witnesses, with other tests demonstrating certain difficulties either with their methodology, application or outcomes. The Board notes that Ms. McShane's DCF and comparable earnings tests were both higher than the upper range of the equity risk premium test and, when applying all three tests, produced a bias in her recommended ROE beyond that sought by NP. The Board is also persuaded by the fact that the equity risk premium test is anchored in the bond market which has demonstrated significantly greater stability in recent years as compared to the equity market. The Board believes, in the absence of evidence which would warrant change, consistent decision making conforming to existing practices promotes a more reliable and stable regulatory environment with less risk. The continuity of the equity risk premium test also has added relevance to the automatic adjustment formula which is considered later in this Decision

The Board will continue to rely principally on the equity risk premium test and will determine a return on regulated common equity primarily with a view to establishing a risk-free rate based on long-term Government of Canada bond yields plus an appropriate risk premium.

iv) Equity Risk Premium Test

Risk-Free Rate

In relying on the equity risk premium test in 1998, the Board established the risk-free rate with reference to the yield on long-term 30-year Government of Canada bonds. The Board determined that 5.75% was an appropriate forecast of the long-term bond rate to be used in setting the risk-free rate. In concert with this decision, the Board similarly ordered that long-term (30-year) Government of Canada bonds be used as the basis for setting the risk-free rate to be applied to the equity risk premium model in introducing the automatic adjustment formula.

Dr. Morin and Ms. McShane based their risk-free rate on a forecast of 30-year bond yields derived from the Consensus Forecast of 10-year Canada bonds plus an allowance for an observed spread between 10-year and 30-year Canada bonds. Both experts used August 2002 Consensus Forecasts which anticipates that the 10-year yield 3-months and 12-months hence will be 5.3% and 6.0% respectively, for an average of 5.65%. Dr. Morin and Ms. McShane concurred on an estimate of 35 basis points as reflecting the recent and historic spread between 10-year and 30-year Canadas which, when added to the 5.65%, provides a 6.0% long-term yield and represents a reasonable forecast on the risk-free rate for the 2003 test year. (Pre-filed Evidence, Dr. R. Morin, pg. 44/5-15**;** Ms. K. McShane, pg. 44/15-23)

Ms. McShane indicated Consensus Forecasts would bring to bear the judgment of forecasters in predicting future long-term bond rates as opposed to actual which are subject to greater cyclical variation. (Transcript, March 25, 2003, pg. 81/7-25)

Dr. Morin suggested stability is enhanced by substituting Consensus Forecast on long-term Canada bonds instead of actual. (Transcript, March 24, 2003, pg. 81/5-8)

Dr. Kalymon selected a risk-free rate of 5.04% which equates with the spot bond yields for 10-year Canada bond rates coincident with the date of his pre-filed evidence. (Pre-filed Evidence, Dr. B. Kalymon, pg. 25/6-7)

NP indicated the recommended risk-free rate proposed by Dr. Morin and Ms. McShane is the method used by the National Energy Board (NEB) and the British Columbia Utilities Commission (BCUC). (Written Submissions, NP, Section C, pg. 29/5-8)

The Consumer Advocate indicates Ms. McShane and Dr. Morin overstate long-term Canada bond rates at a forecast 6%, when actual 30-year rates are only 5.55%. (Final Submission, Consumer Advocate, pg. 45)

In accepting the 6.0% risk-free rate and Consensus Forecast method proposed by NP, the Board would be effectively abandoning its present automatic adjustment formula in favour of the NEB or BCUC model or some variation thereof. Based on the comparison shown in BVP-17, pg. 5 and the evidence during the hearing assessing the performance of each formula, the Board is not convinced that either the NEB or the BCUC model demonstrates sufficiently superior operating characteristics to warrant a change in formula methodology. Depending on the assumptions, it could be argued that the existing Formula methodology actually out-performed either or both of these proposed alternatives. The Board also expresses concern with the notable spread which would have to be factored into the formula between Consensus Forecast and actual long-term Canada Bond yields. The Board believes that greater regulatory stability and consistency is encouraged by retaining the existing methodology and linking the risk-free rate to actual 30-year bond yields.

For additional guidance in determining the appropriate risk-free rate using actual long-term 30-year Canada Bond yields, the Board turned to various references, as follows:

References		Description	Rate
1.	Pre-filed Evidence, Ms. K. McShane, Schedule 4	Average long-term Canada yield 1999-2002	5.75%
2.	Final Argument, Consumer Advocate, pgs. 30-31	Spot yield	5.55%
3.	Transcript, March 24, 2003, pg. 137/22	Spot yield	5.62%

The Board determines a risk-free rate of 5.60% is fair and reasonable.

The Board will utilize 5.60% as the forecast of the risk-free rate to be applied in the equity risk premium test for the test years 2003 and 2004.

<u>Equity Risk Premium</u>

In 1998, in applying the equity risk premium test, the Board determined a risk premium of 3.00%, based on a market risk premium of 5.00% and a relative risk factor of 0.6.

Ms. McShane conducted three equity risk premium tests using a combination of U.S. and Canadian data. The Capital Asset Pricing Model (CAPM) resulted in a market risk of 6.0% - 6.5% and a relative risk factor or beta of 0.6 - 0.65 for a risk premium of an average Canadian utility similar to NP of 4.0%. The remaining tests produced risk premiums of 4.75% - 5.0% and 4.6% (updated to 4.7%). Ms. McShane's risk premium recommendation was 4.0% - 4.75%.

Ms. McShane added 50 basis points to what she refers to as the *"bare-bones"* cost of equity to cover financing flexibility. This adjustment according to Ms. McShane is designed to allow for 3 distinct elements: (1) flotation costs relating to costs upon sale of the new equity; (2) a cushion for unanticipated capital market conditions; and (3) a recognition of the fairness principle between book and market value of stock when comparing regulated utilities with sample industrials. Ms. McShane suggested that to ignore these principles in setting an appropriate financing flexibility adjustment is to ignore the basic premise of regulation. (Pre-filed Evidence, Ms. K. McShane, pgs. 53-54)

Dr. Morin performed six tests which also included a CAPM and an empirical CAPM. Applying a beta of 0.67 to a market risk of 6.7% resulted in risk premiums of 4.5% and 5.0% respectively. These multiple tests used primarily U.S. data and resulted in a risk premium ranging from 4.4% - 6.1% with an average of 5.1%. Weighing this average in favour of the

Canadian data, Dr. Morin concluded a risk premium for NP of 4.5% - 5.0% was reasonable. Dr. Morin made no adjustment to account for financing flexibility.

Dr. Kalymon's risk premium is predicated on his analysis that during 1981-2001 the TSX had realized negative risk premium when compared to long-term Canada bonds. This result, Dr. Kalymon commented, is inconsistent with conventional risk theory but can occur in highly fluctuating markets. Dr. Kalymon reversed to a positive risk premium of the TSX Index by removing the capital gain of bondholders. Following a calculation of the real rate of interest on 10-year Canada bonds at 2.74% (5.04% risk-free rate less 2.3% inflation) and, given equity investment is more risky than bonds, Dr. Kalymon anticipates an average company trading on the TSX should expect a risk premium of 2.50% - 3.00%. Dr. Kalymon concluded no relative risk or beta adjustment is necessary for NP. (Pre-filed Evidence, Dr. B. Kalymon, pgs. 22-28) Dr. Kalymon made no adjustment to his risk premium test but did make a downward revision of 50-100 basis points to both his other tests, DCF and comparable earnings, to account for the lower risk of the regulated versus his industrials sample. (Pre-filed Evidence, Dr. B. Kalymon, pgs. 32/6-7; 34/17-18; 38/11-12)

NP argued the risk premiums derived by Dr. Morin and Ms. McShane are based on long-term economic studies of the differences in actual returns on equity compared to yields on long-term government bonds. NP suggested Dr. Kalymon's equity risk premium approach exercises more subjective judgment than economic theory. (Written Submissions, NP, Section C, pg. 29/13-22; pg. 30/1-5)

The Consumer Advocate submitted both Dr. Morin's and Ms. McShane's recommendations should be rejected as their tests contain primarily U.S. data and their recommendations are considerably higher when compared to regulatory awards in Canada. The Consumer Advocate disputed the subjective characterization of Dr. Kalymon's evidence, citing a 100-year study as a satisfactory alternative determination of the risk premium test. (Final Submission, Consumer Advocate, pgs. 41-45; Transcript, April 25, 2003, pg. 79/5-11)

Financing Costs

Before making a determination on the equity risk premium, the Board is of the view that consideration of the issue of financing flexibility is necessary. The Board notes only Ms. McShane recommended a 50 basis point adjustment for financing flexibility. Despite NP's contention in its written submissions (Section C, pg.17), as indicated above Dr. Kalymon did not make an allowance for financing but adjusted the DCF and comparable earnings test downward by 50-100 basis points to reflect the lower risk of a regulated utility versus his industrials sample. The Board acknowledges that financing costs were incorporated in Order No. P.U. 16(1998-99). The Board believes this regulatory practice varies depending on jurisdiction and notes the Ontario Energy Board in CA-535 (Attachment B) provided for flotation costs whereas in its recent decision 2002 NSUARB 59, the Nova Scotia Utility and Review Board did not make such a provision. (Final Submission, Consumer Advocate, Appendix 2) While limited evidence was brought before the Board concerning financial flexibility, the Board observes 2 of the 3 cost of capital experts made no such allowance. The Board is of the opinion its application introduces a further measure of subjectivity in setting ROE. The Board believes the issue of financing costs are best considered within the context of the equity risk premium.

The Board will make no adjustment to the equity risk premium test for financing costs.

Equity Risk Premium

From an empirical standpoint, Dr. Morin explained that allowed risk premiums expand when interest rates go down and shrink when interest rates go up. This relationship he noted is indicative of the capital market response which is built into the testing process of examining allowed returns. (Transcript, March 24, 2003, pg. 119/13-19) In addition, the Board observes that this relationship has been reflected in historical trends between long-term interest rates and risk premiums in both Canada and the U.S. This trend is also consistent with the findings of the Board following its review of the impact of market conditions on pg. 35 of this Decision.

In considering the appropriate risk premium, the Board highlights the following:

- The investment risk of NP is average overall;
- Long-term bond rates and inflation are anticipated to remain relatively stable;
- A capital structure of 45% equity and 55% debt has been supported by the Board;
- Higher risk premiums allowed in the U.S. bear no discernable relationship to NP and the focus of the Board will be on allowed risk premiums of comparable Canadian utilities; and
- No separate financing costs are being considered.

In light of the above, the Board is of the view that the recommendation of Dr. Kalymon for an equity risk premium of 2.50% - 3.00% is too low. Dr. Morin recommended a risk premium of 4.5% - 5.0% while Ms. McShane recommended a risk premium of 4.0 - 4.75% while later adjusting for financing flexibility of 50 basis points. The Board concludes these are somewhat high.

The Board deems an equity risk premium of 4.15% to be fair and reasonable.

The Board will incorporate a risk premium of 4.15% in the equity risk premium test in calculating the cost of common equity.

v) ROE Summary

The Board summarizes its findings in respect of the equity risk premium test as follows:

Risk-Free Rate	5.60%
Risk Premium	4.15%
	9.75%

The Board will utilize a return on regulated common equity of 9.75% for the purposes of determining the WACC for both 2003 and 2004.

4. Interest Coverage

As previously detailed on pg. 42 of this Decision, interest coverage represents essentially an arithmetic determination which is a function of the capital structure, in particular its debt level, and the ROE reflecting the ability of the company's earnings to cover or meet these debt obligations.

NP noted interest coverage is the principal ratio used by credit rating agencies to assess the creditworthiness of the Company. Exhibit BVP-6 (2nd Revision) demonstrates the nature of this relationship with lower interest coverage depicting greater risk through a combination of higher debt and lower earnings and vice-versa. Exhibit BVP-5 (1st Revision) proposes an interest coverage of 2.50x for 2003 and 2.53x for 2004, assuming a 45% common equity capital structure and an ROE of 10.75% and 10.72% respectively. NP explained it had prepared this application with a target interest coverage at the mid-point in the range of 2.4x to 2.7x identified as suitable in Order No. P.U. 16(1998-99). [Pre-filed Evidence (1st Revision), B. V. Perry, pgs. 15/23;16/1-2]

NP argued the only time in its history that the utility received a downgrade in its bond rating was by S & P following the issuance of P.U. 16(1998-99) when interest coverage was in the lower end of this range. But for the additional revenue generated by the extraordinary events, NP concluded its bond rating would not have been reinstated to *"A"* and a rate hearing would have been necessary to restore NP's financial integrity. (Written Submissions, NP, Section C, pgs. 5; 32; 34; 35)

Given the dispersion of recommended ROEs, not unexpectedly cost of capital experts were divided in their opinion on interest coverage. Dr. Kalymon confirmed he had no difficulty maintaining a recommended 40% capital structure and a return of 8.75% yielding interest coverage in the range of 2x. (Transcript, March 27, 2003, pg. 60/15-21). Dr. Kalymon compared interest coverage for a number of regulated Canadian utilities which showed a mean of 2.65x and a range from 1.80x to 3.56x. Dr. Kalymon concluded NP with a highly stable and very protected market should be able to operate with an interest coverage at the lower end of this range. (Pre-filed Evidence, Dr. B. Kalymon, pg. 14/8-16)

Both Dr. Morin and Ms. McShane disagreed with Dr.Kalymon. Dr. Morin noted S & P's pretax interest coverage benchmark for a single *"A"* utility with a *"very strong"* business risk position is 2.9x. (Supplementary Evidence, Dr. R. Morin, pg. 4/10-11). He indicated his own recommended 45% common equity ratio and ROE translated into interest coverage of 2.5x or 2.6x. (Transcript, March 24, 2003, pg. 22/11-13) Ms. McShane pointed to S & P's guidelines requiring interest coverage of 2.8x-3.4x for a company of comparable business risk to NP. (Pre-filed Evidence, Ms. K. McShane, pg. 10). Ms. McShane observed NP's ability to maintain an *"A"* rating for its recent bond issue at interest coverage considerably less than the lower end of this range may be attributable to S & P placing weight on the fact that NP's bonds are secured by its assets. (Transcript, March 26, 2003, pg. 10/18-20)

The Consumer Advocate argued NP failed to provide any evidence from a bond-rating agency to suggest that the level of interest coverage requested by NP is required for an *"A"* bond rating. The Consumer Advocate suggested that, if S & P has stated that for an *"A"* rating the range is 2.0 - 3.2x and given that agency's reviews of Fortis Inc., the Board should not attempt to over-compensate NP by providing for interest coverage over and above the requirement of the bond rating agency. (Final Submission, Consumer Advocate, pg. 55)

The Board is fully cognizant of the relationship between capital structure and ROE and the measure of risk it attaches to NP as a consequence of its decisions regarding financial targets. As indicated previously, maintaining an appropriate balance between these factors in the interests of both NP and consumers is one of the key challenges faced by the Board in this Application. The Board does not regulate interest coverage but notes the resulting coverage is 2.4x from BVP-6 (2^{nd} Revision) when applied to its findings of maintaining a capital structure of 45% common equity and an ROE of 9.75%. The Board notes a 2.4x interest coverage remains within the range previously accepted by the Board in Order No. P.U. 16(1998-99), though admittedly at its lower end. Given the average risk assigned to NP, the Board believes that this interest coverage serves a realistic and compatible balance between NP and its customers. NP indicated it will not be going to the bond market again until 2006. (Transcript, March 7, 2003, pg. 134/11-15) The Board does not accept that an ROE of 75 - 100 basis points higher than the 9.75% deemed fair and reasonable by the Board is warranted in order to sustain a 2.5x interest coverage based on a capital structure that ranks amongst the most favourable when compared to utilities of equivalent risk.

The Board finds an interest coverage in the order of 2.4x is acceptable given NP's level of risk and the Board's findings in this Decision with respect to NP's capital structure and return on regulated equity.

V. INTER-CORPORATE RELATIONSHIPS AND CHARGES

1. Background

The issue of inter-corporate transactions between NP, its shareholder Fortis, and with affiliated companies has been considered and addressed in previous Orders of the Board. In Order No. P.U. 6(1991) the Board directed the following: (i) a quarterly reporting mechanism be put in place; (ii) NP's code of accounts be modified to identify all inter-corporate transactions; and (iii) NP conduct a study into the financial policies of regulated Canadian utilities with respect to mark up percentages on related party transactions. This study, completed for NP by Deloitte and Touche, was filed with the Board in March 1996. In Order No. P.U. 7(1996-97) the Board: (i) set a deadline for the filing of inter-corporate quarterly transaction reports; (ii) set the basis for allocation of specific charges from Fortis to NP; and (iii) provided direction to NP on the treatment of certain costs as non-regulated or regulated expenses. The Board also accepted the principles presented in the Deloitte and Touche Study ordering that:

- i) inter-corporate services obtained from a competitive market be valued at market;
- ii) in acquiring a competitive service from an affiliate, the allowed regulated expense shall be the lowest cost bid or tariff;
- iii) in cost allocations from affiliates and the parent, transactions must be supported by documentation;
- iv) the markup on the cost must also be supported by reasonable documentation;
- v) a markup may include return on capital only where assets were used to deliver service or good;
- vi) inter-corporate loans involving NP must be valued at their opportunity cost and documentation to support the rate shall be kept;
- vii) pole attachment charges to Unitel shall be valued at the same rate offered to Newtel or CATV operators; and
- viii) postage and courier charges must include labour and the standard overhead charge.

Inter-corporate issues were also raised at NP's 1998 general rate hearing. In Order No. P.U. 36(1998-99) the Board found that the directives set by Order No. P.U. 7(1996-97) and NP's treatment of non-regulated expenses continued to be appropriate and no changes were ordered.

At this hearing issues concerning NP's relationship with its shareholder Fortis and also with other Fortis subsidiaries were raised by the Consumer Advocate. The Consumer Advocate argued that:

> *"the level and complexity of NP's inter-company transactions with Fortis Inc., and all of its related subsidiaries is exposing NP, and therefore ratepayers, to unnecessary financial and insurance risks; reveals that NP may be operating with too many employees; indicates an improper use of regulated funds; and shows that NP is charging preferential interest amounts on outstanding balances due from Fortis related companies, contrary to Section 107 of the Act."* (Final Submission, Consumer Advocate, pgs. 63-64)

The Board has dealt with the financial risks of NP's relationship with its shareholder Fortis on pgs. 38-40 of this Decision. The other issues raised by the Consumer Advocate are addressed separately below.

2. Level of Inter-Corporate Transactions

Board Hearing Counsel observed that Fortis now comprises some nine subsidiaries, eight of which are utilities. (Final Brief, Board Hearing Counsel, pg. 4/4-5) By contrast, there were three utilities referred to in Fortis' 1998 Annual Report. A comparison of Fortis' operating revenues shows NP contributing an estimated 71% in 1998, declining to 57% in 2001. In describing its vision Fortis' 2002 Annual Report states:

> *"The principal business of Fortis will remain the ownership and operation of electric distribution utilities. We will be proactive and innovative in responding to the challenges and opportunities presented by changes in the electricity industry. While the continued profitable expansion of the electric utilities in the Fortis family is our first priority we will also pursue opportunity to acquire other utilities in Canada, the Caribbean and the NorthEastern United States."*

The Board believes the relationship between Fortis, its affiliated companies and NP has become much more complex and integrated since 1998. This relationship extends beyond corporate governance issues between shareholder and subsidiary and has escalated to where NP supplies an increasing level of services to Fortis and its affiliated companies, in particular, insurance and staff, including executive and professional support. NP's regulated and unregulated inter-corporate transactions with Fortis and its sister companies have multiplied several times since 1998 and involve the flow of significant services and charges between affiliates. (Grant Thornton Report-NP 2003 GRA, Schedule 6C) Furthermore, in the case of Central Newfoundland Energy (CNE), Board Hearing Counsel notes professional staff are provided by NP to a sister company, 50% owned by Fortis, which may arguably be viewed as a competitor of NP since it produces energy and sells it in the Province. The Board believes there is no reason to anticipate these transactions between NP and its affiliates will stabilize and the evidence appears to support a continuing escalation, particularly as additional utilities are acquired by Fortis as outlined in its vision. NP argues these inter-corporate arrangements benefit customers of the utility since they generate additional revenues which serve to reduce rates as well as enhance employee development and provide exposure to outside business practices and ideas.

The Board places considerable stock in the advice given by Board Hearing Counsel:

> There is a down side to the Board's openly encouraging Newfoundland Power to pursue this strategy further in that it would further integrate Newfoundland Power possibly into Fortis and the sister companies. And this has implications for the ratings of Newfoundland Power, vis-a-vis it's own stand alone status. So, it's a thorny issue, it's not one that's simply resolvable by addressing it--it's not simply resolvable by suggesting to Newfoundland Power that they just unbridled, go ahead with providing professional services at market rates. But it is something that needs to be monitored and there needs to be a concerted policy put in place so that we can measure this going forward.
>
> (Transcript, April 25, 2003, pg. 157/12-25; pg. 158/1-3)

With regard to the provision of staff and other services to its affiliates, the Board agrees NP may indeed be deriving benefits on behalf of ratepayers. The Board believes, however, such benefits should be transparent, demonstrable and maximized to the advantage of ratepayers. In the absence of these stated objectives, the customers of NP may pay incrementally more for their electricity with either Fortis and/or its other subsidiaries sharing in these benefits. As previously indicated the Board's singular focus in its regulatory responsibility is NP and it is the Board's mandate to ensure electric consumers in the Province enjoy least cost electricity. The Board recognizes it may be several years before NP's next general rate application and, given the ever increasing complexity and number of inter-corporate transactions, it is incumbent upon the Board to ensure the interests of ratepayers are protected.

The Board acknowledges the Deloitte Touche guidelines covering inter-corporate transactions of NP which were put in place in Order No. P.U. 7(1996-97) and went unchanged by the Board in Order No. P.U. 36(1998-99). While these guidelines have generally proven adequate to date, the Board is persuaded in light of the corporate growth of the Fortis family that explicit regulatory policy direction is required to govern NP's inter-corporate transactions into the future. Therefore, in addition to the existing guidelines, NP will be required to observe certain principles in all of its inter-corporate transactions.

The overriding principal that should govern NP is that all inter-corporate transactions between affiliates shall be fully transparent and subject to scrutiny by the Board.

The Board acknowledges the general presumption of managerial good faith but notes that transactions between the utility and its affiliates present unique challenges, as they are non-arms-length transactions. Therefore, the onus will be placed on the utility to establish, to the satisfaction of the Board, that the transaction is prudent and that any corresponding costs reflect *"fair market value"* or *"cost based pricing"*, including a return on invested capital, as appropriate.

The Board has no desire to *"micromanage"* the operations of the utility and places the responsibility with NP to demonstrate to the Board that it has operated in the best interests of the utility and its customers. The Board expects directors and officers of NP to act in a manner which does not prejudice the interests of ratepayers in transactions with affiliates. Inter-corporate transactions between the utility and its affiliates should provide benefit to the electrical consumer and should not be implemented so as to disadvantage the consumer.

NP will be 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.

These principles may be amended by the Board from time to time. Given the implications of these principles on both NP and its affiliates, NP will be required to undertake a review and update of its operating practices and procedures relating to any and all inter-corporate transactions to ensure that the principles as set out above are reflected. The results of such a review shall be reported to the Board no later than March 31, 2004.

3. Centralized Insurance Administration

NP currently handles the insurance administration for Fortis and its subsidiaries. All insurance billings, claims, etc. for the Fortis Group of Companies are coordinated and paid through an employee of NP. NP charges the related companies through inter-corporate billings. The Consumer Advocate argued that *"this is an unusual function for a subsidiary to perform for its parent, and can lead to the exposure of NP to increased insurance costs as a result of its linkage with the insurance risks of other companies over which NP has no control."* The Consumer Advocate further argued that NP has not demonstrated any compelling reasons why it should bear the risk of paying out all of Fortis companies' insurance premiums or why it should remain risk-linked with other Fortis companies. The additional labour and accounting costs associated with performing this function were also questioned. (Final Submission, Consumer Advocate, pgs. 65-66)

In an undertaking to the Consumer Advocate, NP provided information on the relationship of NP's annual insurance premium to the claims experience of other Fortis companies. (U #1) This information included a comparison of loss ratios (ratios of the total claims under a policy of issuance to the total premiums paid for coverage under the policy) for the Fortis Group of Companies and NP. The loss ratios for Fortis and NP for auto and liability policies are comparable; loss ratios for property are 208% for Fortis and 147% for NP; and loss ratios for all coverages is 149% for NP compared to 152% for Fortis. Total insurance premiums for 1997-2003 for the Fortis Group were $5,912,915 with $3,071,518 (51%) allocated to NP. In U #1 NP also identified the following benefits of participating in a group insurance program:

1. diversity of claims experience among a group of insured parties can benefit participants who experience higher incidence of claims in a given period;
2. volume discounts on premiums available as a result of the spreading of risk and economies of scale;
3. savings resulting from sharing of broker services; and
4. improved access to leading specialty insurance markets, such as those specializing in insuring utility risk.

In written submission (Section D, pg. 16) NP argued that its centralized insurance management is more cost effective than if it were to purchase insurance on its own as a small electric utility.

It is unusual, in the Board's view, for a subsidiary company to perform a centralized function such as insurance administration for the parent company and its affiliates. The Board's primary concern in this matter is that ratepayers are not subsidizing or contributing to the insurance expenses of Fortis and related companies and also that there is no additional cost to NP (and hence ratepayers) of NP's participation in a group insurance program. NP has argued that there is a benefit to maintaining the insurance expertise in-house rather than having to out-source. Based on the evidence the Board is satisfied that the insurance costs are tracked and billed to the related companies as required. The labour charges for NP's staff persons associated with the activity are billed as well, including the appropriate markups. Inter-corporate charges are reported to the Board quarterly and reviewed by the Board's Financial Consultants as part of their annual financial reviews.

A more difficult issue for the Board is the determination of whether there is actually a benefit accruing to NP and its ratepayers as a result of this activity. Mr. Perry indicated that NP had not gone to market for a stand-alone quote for insurance coverage based on NP's risks alone. While the benefits listed by NP above relate primarily to cost savings, these savings have not been quantified and the Board has no information before it to satisfy itself on this question. On this issue the Board agrees with the Consumer Advocate's submission that NP should be directed to demonstrate that there is a real, quantifiable benefit to ratepayers for NP to remain as the central insurance administrator for Fortis and its subsidiaries and that there is a real benefit to ratepayers for NP to continue to participate in the group insurance plan rather than to be insured on a stand-alone basis.

NP will be directed to prepare a report which should compare and quantify the benefits to NP and ratepayers of its administration of and participation in a centralized insurance program for the Fortis Group of Companies, rather than be insured on a stand-alone basis. This report should be filed with the Board no later than March 31, 2004.

NP will be required to modify its quarterly reports on inter-corporate charges to show separately associated labour and other staff and expense charges billed in relation to NP's insurance administration on behalf of Fortis and related companies.

4. Inter-Corporate Staff Exchanges and Associated Charges

The Consumer Advocate raised the issue of the number of NP's employees working for affiliated companies and the charge for these transactions. Specific concerns raised include the charge rate for Mr. Hughes, NP's President and CEO, for doing work for Fortis companies, and the increasing level of staff charges billed to Fortis for NP's employees working on behalf of Fortis or related companies. The Consumer Advocate submits that *"NP has excessive staff if it is able to operate without the staff that generated the $1,600,000 in staff charges to Fortis companies in 2002."* (Final Submission, Consumer Advocate, pg. 67)

The Board has already addressed the issue of the level of inter-corporate transactions and has identified the principles that should govern inter-corporate activity between NP and affiliated companies. The Board's responsibility in this area is to ensure that ratepayers are only paying for those costs necessarily incurred by NP in the provision of electrical service.

NP bills Fortis and its related companies for time spent by NP employees working with these companies based on timesheets and the individual specific rate of pay plus a loading factor to recover related overheads. It also bills affiliated companies all out-of-pocket expenses, which are passed on at cost. Certain engineers and technicians are charged at market rates where market rates are ascertainable. The Board's Financial Consultants review inter-corporate charges each year and report to the Board. A review of Schedule 6A of Grant Thornton's report filed in this proceeding indicates that the level of staff charges to Fortis has increased since 1999. (Grant Thornton Report-NP-2003 GRA) As well it is apparent that the increase in Fortis' interests in other electrical utilities such as Fortis US Energy Corp., Belize Electricity Limited, Belize Electric Company Limited and CNE, has resulted in additional inter-corporate staff charges since 1999.

According to CA-666 the percentage of Mr. Hughes' total compensation charged to Fortis and related companies has been in the range of 18% each year since 1999, with the exception of 2001 when 25% of Mr. Hughes' total compensation was charged. In addition to this direct compensation charge NP also bills for associated overhead costs on an hourly basis. CA-667 provided similar information for other NP executives. This information indicates that a portion of the total compensation for other executives is also billed to Fortis and related companies but that the percentages are much lower than that charged for Mr. Hughes. Of the remaining executive Mr. Perry, NP's Vice President Finance and CFO, has the most significant charge, with 21% of his total compensation charged in 2001 and 17% charged in 2002.

In addressing this issue in cross-examination the Consumer Advocate suggested that the charge out rate for Mr. Hughes is in the order of $170 per hour, based on the evidence filed in the hearing. (Transcript, March 3, 2003, pg. 158/21-9) In response, Mr. Hughes could not confirm the rate nor whether that rate is in his opinion a market rate for a CEO since he does not have a benchmark.

> Q. Is your answer then that that would be a market rate?
>
> A. I don't know. I mean, obviously what a CEO gets paid for is to produce far more value and make more changes and set the direction than what they're getting paid. To be honest, I can't think of an example where a CEO is charged out to a non-related company. So I haven't got a benchmark, so I suppose, Mr. Fitzgerald, I'm neither agreeing or disagreeing, I just don't—I can't think of a comparative.

Based on the evidence the Board is satisfied that the time for NP's employees, other than executive and management, is being recorded and charged out to Fortis and affiliated companies at market rates or other appropriate rates. In the Board's view this should also be the case for executive and management, rather than using a cost plus overhead basis. This approach in the Board's view recognizes the value of the service being provided by NP. If a market rate is not ascertainable (as seems to be the case), NP should add an appropriate premium to its cost-based rates as a proxy.

As part of the review of operating practices and procedures relating to inter-corporate transactions NP will be required to investigate the utilization of market rates for executive and management time charges. In lieu of market rates, NP shall propose an appropriate markup on its cost-based rates as a proxy for market in the event that utilization of market rates is not practical.

5. Billing Practices and Interest Arising from Inter-Corporate Transactions

The Consumer Advocate also raised the issue of billing practices to related companies for inter-corporate transactions, specifically the timing of billings and interest charges on overdue accounts. It was submitted by the Consumer Advocate that *"the billing out of NP staff charges on a quarterly basis, where the cost to pay the staff and provide travel funds are incurred on a monthly, if not weekly, basis by NP, reveals a significant benefit that Fortis and its affiliates receive from NP."* (Final Submission, Consumer Advocate, pg. 68) The Consumer Advocate also argued that NP's practice of not charging these companies interest for overdue accounts is unfair to consumers and is in contravention of Section 107 of the *Act*, which essentially prohibits preferential billing.

During the hearing, in response to questioning from the Consumer Advocate regarding timing of insurance billings and subsequent payments, Mr. Perry acknowledged that NP has incurred a cost associated with receivables over 30 days from related companies. In an undertaking NP provided a pro-forma calculation of interest that would have accrued in each of years 2000-2002 on inter-corporate receivables over 30 days if interest had been charged based on NP's average short-term borrowing rate for that year. This information showed that the interest charges would have totalled approximately $12,400. (U #16) Mr. Perry also testified that this issue of billing practices to Fortis and related companies has been addressed and corrected. (Transcript, March 13, 2003, pg. 120/9-19)

The Board is satisfied that the time and expenses relating to inter-corporate transactions are being tracked and recorded as required, and that NP is billing and recovering those costs from related companies. The Board expects, however, that the billings for these services performed by NP on behalf of related companies be treated in the same manner as any billings for amounts owing that NP would issue to a non-related company as part of its normal trade or business practice. The Board's finds that this is one of the ways that it can assure itself that NP is not treating its billings and receivables to Fortis and affiliates differently than it would any other unrelated party to which it provides service. It follows that billings to Fortis and related companies should be issued on the same terms and conditions, and be assessed appropriate interest charges and penalties in the case of late payments, as for non-related parties. It is not clear from the evidence that this is the case. For example, NP calculated the pro-forma interest in U #16 using its average short-term borrowing rate, which the Board estimates to be approximately 4% - 4.5%. This interest rate appears to be much lower than the interest rate or penalty that would normally be applied to outstanding bills, which is typically calculated on a prime rate plus basis. The Board also expects billings to Fortis and related companies to be undertaken within 30 days of the service and/or expenses being charged for recovery.

NP will be required to apply billing and collection practices with respect to inter-corporate transactions which are consistent with those applied to unrelated parties. Billings to Fortis and related companies should also be undertaken within 30 days of the service and/or expenses being charged for recovery.

VI. AUTOMATIC ADJUSTMENT FORMULA

In Order No. P.U. 16(1998-99) and P.U. 36(1998-99) the Board ordered the use of an automatic adjustment formula (the *"Formula"*) to set an appropriate rate of return on rate base for NP on an annual basis. The Board also determined that after NP's rate of return on rate base had been set for three consecutive years using the Formula, and without a hearing, then a hearing will be convened in the following year to consider the cost of capital, including a full review of forward looking test year projections.

The Formula put in place by the Board in 1998 is as follows:

$$\textbf{Rate of Return On Rate Base} = \left[\frac{\textbf{Invested Capital}}{\textbf{Rate Base}} \times \textbf{Weighted Average Cost of Capital} \right] + \frac{\textbf{Z}}{\textbf{Rate Base}}$$

Where Z represents amounts which are recognized in the calculation of either weighted average cost of capital or rate of return on rate base, but not both. These amounts include:

(A) Amortization of Capital Stock Issue Expenses;
(B) Interest on Customer Deposits; and
(C) Interest Charges to Construction.

The Formula adjusts NP's rate of return annually based on changes in the forecast cost of common equity. This forecast change is based on changes in long term Government of Canada Bond yields. By use of an equity risk premium approach the Board determined that the appropriate return on regulated equity for NP was the sum of the risk free cost of capital (i.e. the average of long term Government of Canada bond yields) and an adjusted risk premium which varies based upon the changes to the risk free cost of capital. The resulting rate of return on common equity, along with the appropriate rate of return on preferred equity and the embedded cost of debt are then used to calculate the Weighted Average Cost of Capital (WACC). The appropriate rate of return on rate base is calculated by multiplying this WACC by the ratio of forecast average invested capital to forecast average rate base plus a Z factor as shown above. The Formula also adjusts on an annual basis the ROE, forecast average invested capital and average rate base. All other components of the Formula are based on 1999 test year data.

1. Existing Formula Performance

The Formula has been used in each of 1999, 2000 and 2001 to set the rate of return on rate base (and hence rates) for NP for the years 2000, 2001 and 2002. In Order No. P.U. 28(2001-2002) the Board ordered, among other things, that NP undertake a review of the performance of the Formula. The results of this review were filed as part of the evidence in this proceeding. (Exhibit BVP-17)

The following table shows the allowed range of return on rate base as set by the Board for 1997-1999 and as derived by the Formula for 2000-2002 and, for comparison purposes, the actual returns achieved by NP:

Returns on Rate Base: 1997 to 2002			
Year	Allowed Rate of Return	Allowed Range (%)[1]	Actual Return (%)[2]
1997	10.65	10.50- 10.80	10.71
1998	9.81	9.63 - 9.99	9.86
1999	9.98	9.80- 10.16	10.04
2000	10.28	10.10- 10.46	10.46
2001	10.28	10.10- 10.46	10.46
2002	10.06	9.88- 10.24	9.94

[1] As set out in various Board Orders.
[2] As reported by NP in its annual returns.

Consumer electricity rates were set each year based on the rate of return on rate base, which is the midpoint of the allowed range of return set by the Board, using a 36 basis point spread. The operation of the Formula resulted in adjustments to rates for 2000 and 2002 of less than 1% with rates remaining unchanged in 2001.

One of the conclusions of the Formula review contained in BVP-17 is that the Formula yielded a low return on common equity when compared to similar mechanisms adopted by the NEB and the BCUC.

A significant issue raised during the hearing was the increasing spread between the actual rate of return on rate base and the actual rate of return on regulated equity. This issue was highlighted by Grant Thornton as part of their annual reviews of the operation of the Formula for 2000 and 2001. The following comparison of the actual return on average regulated common equity with the actual return on average rate base for 1998 to forecast 2002 was provided by Grant Thornton (Grant Thornton Report-NP 2003 GRA, pgs. 19-20):

Comparison of Actual Returns on Rate Base and Regulated Common Equity					
	1998	1999	2000	2001	Forecast 2002
Return on Average Common Equity	9.58%	9.81%	10.80%	11.35%	10.32%
Return on Average Rate Base	9.86%	10.04%	10.46%	10.46%	9.79%
Spread between actual returns	(0.28%)	(0.23%)	0.34%	0.89%	0.53%
Spread based on formula returns	-	(0.73%)	(0.69%)	(0.69%)	(1.01%)

In its evidence NP describes two events which have affected the returns for 2000 and 2001 i.e. the treatment of GEC for income tax purposes and the Aliant pole purchase. Grant Thornton adjusted the returns for the effect of these two events as shown below:

Returns Adjusted for Extraordinary Events per Exhibit BVP-2					
	1998	1999	2000	2001	Forecast 2002
Return on Average Common Equity	9.58%	9.81%	9.92%	8.50%	9.43%
Return on Average Rate Base	9.86%	10.04%	10.07%	9.23%	9.47%

Grant Thornton also prepared an analysis of the impact of changes in the individual components of the Formula. As a result of this analysis two additional areas were identified for further consideration by the Board: (i) changes in forecast versus actual embedded cost of debt; and (ii) changes in forecast versus actual ratio of average invested capital to average rate base.

Before considering the evidence put forward in the hearing regarding proposed changes to the Formula the Board wishes to provide its opinion and findings regarding the effectiveness of the Formula since 1998 and on the continued use of the Formula for setting rates beyond this Decision.

2. Board's View on Continued Use of the Formula

The appropriateness of implementing an automatic adjustment mechanism for resetting the rate of return in years subsequent to a test year to reflect changes in financial benchmarks was considered by the Board in NP's 1998 cost of capital hearing. In Order No. P.U. 16(1998-99) the Board stated the following (pg. 103):

> *"The Board is of the view that there is merit to a formula, in light of the cost of a full cost of capital hearing and the potential savings to consumers which could be realized. The Board also believes that the adoption of an automatic adjustment mechanism will create greater predictability, which will thereby reduce the risk of regulatory uncertainty. In the opinion of the Board, a mechanism to facilitate an annual review at modest costs will be of benefit to the ratepayer and the Company."*

The Board also stated in Order No. P.U. 16(1998-99) that it would call a hearing if circumstances change, so as to render the use of an automatic adjustment formula to be inappropriate, citing specific examples on pg. 104 as follows:

a) deterioration in the financial strength of the Company, resulting in an inappropriately low interest coverage;
b) changes in financial market conditions which would suggest that the formula is not accurately reflecting the appropriate return on equity; and
c) fundamental changes in the business risk of the Company.

The Board has monitored the operation of the Formula as part of its ongoing supervisory role in regulating the utility. Revised values for rate base and invested capital for use in the Formula for each year were reviewed and approved by the Board as part of that year's capital budget hearing. The Board's financial consultants reviewed the operation of the Formula as part of their annual financial reviews of NP. As well NP was required to file quarterly reports with the Board which, in addition to the required annual report, provided information on actual financial performance, both regulated and non-regulated. In Order No. P.U. 36(1998-99) the Board also specified the time period for the setting of rates using the Formula to three consecutive years, after which a full cost of capital hearing would be convened.

As stated in Order No. P.U. 16(1998-99) one of the primary motivations for adopting the Formula was the potential savings to be realized from a regulatory process that does not require frequent cost of capital hearings, which are time consuming and expensive. It was also recognized that the use of a formula may reduce regulatory risk due to the certainty associated with an automatic adjustment mechanism in reflecting changing financial conditions. In the Board's view the use of the Formula has contributed to stable rates for consumers and lower regulatory costs since 1998. Rate changes due to the operation of the Formula have been +0.71% in January 2000, no change in January 2001 and a decrease of 0.56% in 2002. Many of the issues raised during this hearing relating to NP's earnings and the impact of extraordinary events on those earnings do not relate to the operation of the Formula and are discussed elsewhere in this Decision. None of the parties advocated abandoning the Formula but rather proposed specific changes to the Formula on a go forward basis.

In the Board's view there is merit in continued use of a formula for the same reasons as set out in Order No. P.U. 36(1998-99) and stated above. This was the Board's first experience with an automatic adjustment mechanism and, based on the evidence in this hearing, the Board believes that adjustments to the Formula itself and implementation of specific triggers leading to a review of the Formula's components will improve its operation and effectiveness.

3. Changes as Proposed by NP

In this Application NP is proposing three changes to the Formula: 1) change the manner of determining the risk free rate by adopting the method utilized by the National Energy Board (NEB) and the British Columbia Utilities Commission (BCUC); 2) adopt an equity risk premium of 4.75% at a risk free rate of 6%; and 3) expand the range of return on rate base to 50 basis points. These proposals are discussed in detail in the following sections.

i) Risk-Free Rate

NP stated that the calculation of the risk-free rate in the Formula as put in place by the Board is out of step with similar mechanisms currently in use in Canada and that, as a result, "*NP's returns are established by means outside of the mainstream for such mechanisms in use for Canadian utilities*" [Pre-filed Evidence, B. V. Perry, (1st Revision), pg. 47/1-2]. Mr. Perry goes on to state that the short observation period for setting the risk-free rate exposes NP's investors to additional risk.

The risk-free rate used in the existing Formula is based on the actual yields of two series of long-term Government of Canada bonds. The observed average of the daily closing yields for the last five trading days of October and the first five trading days of November for Government of Canada 8% Issue, maturing June 1, 2027 and the 5.75% Issue, maturing June 1, 2029 is used to forecast the risk-free rate for the upcoming year.

NP proposes that the Formula be amended to adopt the NEB and BCUC approach to determining the risk-free rate. The NEB's formula uses a forecast 10-year bond yield as calculated by taking the average of the 3-month and 12-month-out forecasts of 10-year Government of Canada bond yields as set out in the November issue of *Consensus Forecasts* (published by Consensus Economics Inc., London, England). This forecast 10-year bond yield is added to the observed spread between the 10-year and 30-year Government of Canada bond yields for the current year, calculated by averaging the yields published daily in the National Post throughout October of the current year, to provide a forecast risk-free rate for the next year. The BCUC uses the same calculation for the forecast risk-free rate.

NP provided a comparison of the risk-free rate forecasts and actual 30-year Government of Canada bond yields for 1999 to 2002 as outlined below (Written Submissions, NP, Section G, pg. 8):

Comparison of Risk Free Rate Forecasts and Actual 30-Year Government of Canada Bond Yields: 1999-2002 (%)				
Forecasts:	**1999**	**2000**	**2001**	**2002**
Newfoundland	5.49	6.18	5.75	5.50
NEB	5.69	6.12	5.73	5.63
BCUC[1]	5.47	6.04	5.73	5.63
Actual Yields[2]	**5.72**	**5.71**	**5.76**	**5.68**

[1]In 2000 the BCUC adopted a longer observation period to establish the forecast spread between 10 and 30-year bond yields.
[2]Actual yields are the average of Bank of Canada published month end yields for 30-year Government of Canada Bonds for each year.

NP submitted that the table above provides conclusive evidence that the NEB formula has greater predictive accuracy and lower volatility in predicting the risk-free rate than the existing methodology contained in the Formula. Dr. Morin and Ms. McShane agreed with this proposed change, principally because of its relative stability as compared to spot observations of long-term Canada bond yields.

The Consumer Advocate does not support this proposed change, and stated that "*if the Board is to continue with a formula it should continue with the ten trading days' methodology as provided for in P.U. 16 (1998-99)…*" (Final Submission, Consumer Advocate, pg. 28). Dr. Kalymon suggested that the existing formula methodology for calculating the risk-free rate has been more accurate than the NEB's methodology.

As stated previously in this Decision the Board is not convinced that either the NEB or the BCUC model demonstrates sufficiently superior operating characteristics to warrant a change in formula methodology. The Board believes that greater regulatory stability and consistency is encouraged by retaining the existing Formula.

The Board will continue to use the existing methodology in the Formula for calculating the risk-free rate. However, the risk-free rate will now be calculated based on the actual yields of the three most recent series of long-term Government of Canada bonds

during the 10 trading days being monitored as reported in The Globe and Mail under the heading *"Ask Yields"*. The observed average of the daily ask yields for the last five trading days of October and the first five trading days of November for these three most recent issues will be used to forecast the risk-free rate for the upcoming year, in each year of operation of the Formula.

ii) Equity Risk Premium

NP is also proposing that the Formula be amended by establishing, at a risk-free rate of 6.0%, an equity risk premium of 4.75%.

In Order No. P.U. 16(1998-99) the Board determined that the total risk premium (including an allowance of 50 basis points to cover underwriting costs, the risk of dilution of share value and unforeseen circumstances) to be used in the Formula with a risk-free rate of 5.75% was 350 basis points, or 3.50%, to give an ROE of 9.25%.

The Board has determined that a total risk premium of 415 basis points, or 4.15%, is reasonable. This is the value that will be used and adjusted on the same basis as was ordered in Order No. P.U. 36(1998-99) in the application of the Formula.

4. Embedded Cost of Debt

The issue of the variance between the embedded forecast cost of debt used in the Formula and the actual cost of debt was raised by Grant Thornton (Grant Thornton Report-NP 2003 GRA, February 4, 2003, pg. 22). In Order No. P.U. 36(1998-99) the Board fixed the embedded cost of debt for purposes of the Formula at 9.18%. This cost of debt remains constant from year to year. Actual embedded cost of debt for 1999 to 2001 has been below that used in the Formula, ranging from 9.01% in 1999 to 7.79% in 2002. According to Grant Thornton:

> *"The decrease in the embedded cost of debt means that actual interest costs are lower than anticipated in the Formula. Generally speaking, assuming other items are constant, as interest costs decrease earnings increase and vice versa. What this means in terms of the operation of the Formula is that because the cost of debt is set at a higher level than actual, the Company has the opportunity to increase the return on equity while still staying within the limits of rate of return on rate base."*

Grant Thornton suggested the Board consider the significance of variations in the embedded cost of debt and whether the Board should consider modifying the Formula to adjust for forecast changes in the embedded cost of debt annually. In supplementary evidence Grant Thornton suggested that, as an alternative to modifying the cost of debt annually in the Formula, the Board may establish criteria which would trigger a review of the Formula and the cost of capital. This review would be triggered whenever certain variables or returns generated by operation of the Formula vary significantly from expectations. (Supplementary Evidence, Grant Thornton, pg. 3)

The Consumer Advocate submitted that the operation of the Formula unadjusted for the true cost of embedded debt has resulted in additional income of approximately $7,500,000 for NP for the years 2000, 2001 and 2002. This extra income, according to the Consumer Advocate, contributed to NP's over-earning on its equity in each year since the implementation of the Formula. The Consumer Advocate supports the annual adjustment of the forecast embedded cost of debt. (Final Submission, Consumer Advocate, pgs. 36-39)

The Board agrees that the changes in the embedded cost of debt from that set by the Formula for the 1999 test year have contributed in part to the earnings above the ROE used in the Formula. These changes in debt costs are caused by a number of factors, however, including use of more short-term debt by NP to finance its operations, and changes in interest rates. In addressing this issue in the context of the Formula the Board does not wish to put mechanisms in place that would restrict the ability of NP's management to lower costs, including debt costs, between cost of capital hearings. The real issue for the Board is how the benefit of these lower costs is passed on to consumers.

In the Board's view it would be contrary to the purpose of having an automatic adjustment mechanism if, once a formula has been established, the Board were to use variances from forecasts of requirements to adjust various formula components as they change. In implementing a formula the Board must select reasonable and justified test year values based on the evidence. In the Board's view this is consistent with the prospective nature of setting rates. Changes in test year values are expected. The primary concern for the Board is to ensure that the components in the Formula remain appropriate. This was recognized by the Board in Order No. P.U. 36(1998-99).

The Board concludes that a triggering mechanism tied to the overall cost of capital would be more appropriate. This will provide the Board with the opportunity to review not only the components of the Formula but also to examine the reasons for the variances from test year values. If the variances are related to changing financial and market conditions that the Board or parties could not have foreseen or anticipated, an adjustment to the Formula may be appropriate. The Board does not want, however, to discourage NP from continuing to seek efficiencies to lower costs and will focus primarily on those components that remain outside the control of the utility. As an added monitoring mechanism the Board will require NP to provide additional information on changes in the embedded cost of debt as part of its annual returns.

NP will be required to modify the schedule filed as part of its annual return that calculates the embedded cost of debt to identify specifically the causes of variations in the actual embedded cost of debt from the cost forecast for the test year period.

5. Trigger Mechanism for Early Review

From the Board's perspective, a significant indicator that the Formula may not be operating as intended in setting the rate of return on rate base is when NP's actual earned return on regulated equity in a given year is significantly higher than the expected return or cost of equity determined for that year. In this context it is logical that the triggering mechanism for an early review of the Formula be some pre-defined threshold for the observed rate of return on regulated equity. The Board finds that a good reference point for the threshold is the upper limit of the range of return on rate base. The threshold should be higher than the upper limit otherwise a review would be triggered even though the utility did not earn outside the allowed range.

The Board feels that an appropriate trigger point would be when the actual rate of return on regulated equity for any given year is greater than 50 basis points above the cost of equity as determined by the Formula. Where in any year this threshold trigger is exceeded, the Board will require NP to file a report, as part of its annual return, which details the variations in all components of the cost of capital and explains the circumstances or facts leading to such variations. The Board will undertake an immediate review of this information and make an assessment as to the most appropriate course of action which may involve calling for a hearing on cost of capital.

The Board will establish a mechanism tied to the observed rate of return on regulated common equity which may trigger an early review of the Formula and cost of capital. Where the actual rate of return on regulated equity in any intervening year exceeds the cost of equity determined by the Formula by more than 50 basis points, then NP will be required to file a report with the Board in its annual return setting out the circumstances and facts contributing to the difference.

6. Period of Operation

NP set out its position on the period of operation of the Formula in its response to CA-343. NP has proposed that the Formula be used for a further three year period, stating that customer rates should be set for 2003 and 2004 by Order arising from this hearing and the Formula be used to set rates for 2005, 2006 and 2007. This would mean, presumably, that NP would come before the Board no earlier than late 2007 or early 2008 for a cost of capital hearing unless circumstances change such that an earlier hearing is required by the Board or requested by NP.

It is evident from the record that there are several events that will occur in the next 2-3 years that may impact NP's financial position. These were summarized in the final brief of Board Hearing Counsel (pg. 24). The specific impacts of these events on NP cannot be determined at this time, especially those events outside NP's control, such as the outstanding CCRA issue and the outcome of S & P's ratings review. If either of these events has a negative or material impact on NP's financial position the Board anticipates that NP will request an earlier hearing to review its cost of capital. However, the Board is of the opinion that the proposed period of operation of the Formula for a three-year period starting in 2004 (i.e. to set rates for 2005, 2006 and 2007) is reasonable and meets the intended objective of regulatory efficiency and stability. The Board has put in place with this Decision a triggering mechanism which, along with the Board's ongoing monitoring, will provide the opportunity for the Board to convene an early review if deemed necessary.

The Board will approve the use of the Formula, as modified by this Decision, for a further three-year period. Customer rates will be set for 2003 and 2004 by this Decision and Order. The Formula will be used to set the rate of return on rate base, and hence customer rates, for 2005, 2006 and 2007.

7. Ratio of Average Invested Capital to Average Rate Base and Inclusion of Deferred Charges in Rate Base

Deferred Charges

In its review of the Formula Grant Thornton observed, as inputs are updated annually, the resulting calculation adds both complexity and variability to the operation of the Formula. For example, deferred charges such as pension costs which may fluctuate substantially from year to year are included in invested capital but not in rate base. Grant Thornton suggests that if the Board wishes to improve the operation of the Formula one alternative the Board may wish to consider is the Asset Rate Base method, where all regulated assets of the utility are included in rate base. The Asset Rate Base method is applied to NLH and is an equally acceptable regulatory practice which would more closely equate rate base and total required invested capital. Grant Thornton points out, however, that even with the inclusion of deferred charges in rate base a difference still remains between NP's average rate base and average invested capital. Grant Thornton reconciles this difference as $3,799,000 in 2003 and $2,858,000 in 2004. (Supplementary Evidence, Grant Thornton, pgs. 3-4) Grant Thornton acknowledges these remaining differences should eventually be absorbed into the Asset Rate Base model but this will require further analysis and is best left to NP's next general rate application. (Transcript, April 8, 2003, pg. 13/16-25)

Grant Thornton explained including deferred charges into NP's rate base under the Asset Rate Base method will add approximately $77,000,000 to the rate base in 2003 but will not increase revenue requirement as NP is also recovering these costs through the current Invested Capital approach. Grant Thornton noted that deferred charges are forecast to increase significantly over the next five years and suggested that the Board apply a prudence test each year to deferred charges in conjunction with its hearing of the company's capital budget application. (Supplementary Evidence, Grant Thornton, pgs. 3-4; Exhibit II)

NP indicated that Grant Thornton's alternative does not appear to affect the balance between the interests of the utility and its customers and that the Board is free to make choices between reasonable regulatory alternatives. (Written Submissions, NP, Section G, pg. 5/1-7) The Board Hearing Counsel indicated that if the Board were to adopt the Asset Rate Base method as recommended, it will need to establish a reporting process and review guidelines for testing the prudence of pension related expense, as their determination involves expert actuarial evidence and the exercise of considerable management discretion. (Final Brief, Board Hearing Counsel, pg. 22/22-30)

The only expert commenting on the issue, Mr. J.T. Browne, appeared indifferent to either option as long as the cost of financing the investment is recovered and regulatory accounting principles are followed. Mr. Browne commented that in his experience there is generally a presumption of prudence unless there is evidence to the contrary. (Transcript, March 31, 2003, pg. 71/15-25; pg. 78/11-14)

The Board finds that changing the Formula and adopting the Asset Rate Base method will result in a consistent approach to determining rate base for both NP and NLH. Furthermore, the

Formula will also be simplified and the results more stable year over year. The Board will require NP to observe appropriate guidelines to ensure proper annual monitoring of these deferred charges. The Board acknowledges NP's understanding that this change has no impact on the utility but notes in the reconciliation of the remaining differences based on the Asset Rate Base method more work is required. Whether or not these subsequent adjustments will be revenue neutral for NP is uncertain. The Board indicates, however, these issues will be a subject of the NP's next general rate hearing, at which time the evidence of all parties will be heard.

Regulated verses Book Equity

In its written submission, NLH addressed the issue of utilizing return on *"regulated common equity"* versus return on *"book value"* in measuring NP's return on equity. The difference between regulated equity and book equity is one of the reconciling items noted by Grant Thornton in their reconciliation of Average Invested Capital and Average Rate Base (including deferred charges). (Supplementary Evidence, Grant Thornton, Exhibit II) NLH submitted that, in moving to the Asset Rate Base method for NP, the Board may consider discontinuing the use of regulated common equity in favour of book equity.

The Board believes that the arguments put forward by NLH with respect to using book equity have considerable merit, however, the Board is not prepared to make such a change in regulatory practice at this time. As noted above, this is one of the remaining reconciling items between Invested Capital, as currently calculated, and Rate Base. The Board will direct NP to address all reconciling items, including this issue, no later than its next general rate application.

The Board finds that the Asset Rate Base method should replace the Invested Capital approach currently used to calculate NP's rate base. The move to the Asset Rate Base method will begin in 2003 by incorporating deferred charges in rate base. The Board will direct NP to implement the following guidelines in switching to the Asset Rate Base method:

- **(i) Average deferred charges based on BVP-11 to be added to the average rate base for the 2003 and 2004 test years and all subsequent fiscal years.**
- **(ii) Evidence relating to changes in deferred charges, in particular deferred pension costs, to be filed annually at the capital budget hearing.**
- **(iii) NP will provide a reconciliation of average Rate Base to average Invested Capital annually at the capital budget hearing.**
- **(iv) NP will review no later than its next general rate application, the appropriateness and approach to including the remaining reconciling items in the Rate Base. This review will address the issue of discontinuing the use of regulated common equity in favour of book equity.**

VII. RATE BASE

1. Average Rate Base and Return on Rate Base

NP's average rate base comprises investment in plant and equipment less accumulated depreciation to which is added an amount owed to NP by its customers in the Weather Normalization Reserve and allowances for inventory and cash working capital and from which is deducted amounts for Contribution in Aid of Construction ("CIAC"). The return on rate base comprises the cost of debt, rate of return on preferred equity and rate of return on regulated common equity.

The average rate base, return on rate base and rate of return on rate base is calculated on pg. 8 of Exhibit BVP-1 (1st Revision) for 1998 through to 2002 and forecast for 2003 and 2004. A summary of the relevant rate base figures presented by NP is as follows:

Financial Results and Forecasts
Rate of Return on Rate Base
(000's)

	Historical Data					Proposed	
	1998	1999	2000	2001	2002	2003	2004
Return on Regulated Common Equity	$ 22,299	$ 23,639	$ 27,237	$ 29,699	$ 29,518	$ 31,822	$ 33,429
Return on Preferred Equity	626	626	626	623	613	613	613
Finance Charges	25,233	26,488	26,641	26,700	26,853	30,774	31,626
Return on Rate Base	48,158	50,753	54,494[1]	57,024[1]	56,984	63,209	65,668
Average Rate Base	488,204	505,688	520,979	545,162	573,337	599,245	622,650
Rate of Return on Rate Base	9.86%	10.04%	10.46%	10.46%	9.94%	10.55%	10.55%

[1] Subject to rounding

NP's proposed rate of return on average rate base for 2003 and 2004 is 10.55% arrived at by dividing a forecast return on rate base of $63,209,000 (2003) and $65,668,000 (2004), by an average rate base of $599,245,000 and $622,650,000 respectively.

Grant Thornton conducted a review of the pre-filed evidence comparable to these revised figures and concluded that the results were calculated in accordance with established practice and contained no discrepancies. (Grant Thornton Report – NP 2003 GRA, pgs. 21; 26)

The Board heard no evidence contesting NP's proposed rate base calculations for 2003 and 2004 but notes these specific numbers will change based on other findings of the Board as contained in this Decision.

Specifically, the Board has determined that effective in 2003 the Asset Rate Base method will replace the Invested Capital approach currently used to calculate NP's rate base and as a result deferred charges will now be incorporated in this rate base.

Based on this decision the Board calculates the impact on average rate base for the 2003-2004 test year period as follows:

	2003 (000's)	**2004 (000's)**
Average Rate Base as proposed by NP	\$599,245	\$622,650
Average deferred charges	\$72,970	\$80,452
Revised average Rate Base	\$672,215	\$703,102

The rate of return on rate base proposed by NP for the test year period is 10.55%. The decision to include deferred charges in rate base affects the translation of the weighted average cost of capital into an allowed rate of return on rate base. In moving to the Asset Rate Base method the Board accepts the premise that the change should be neutral in terms of its impact on total allowed return and revenue requirement. The Board calculates the change in revised rate of return on rate base for the test year period based on NP's Application and incorporating the Board's decisions on rate base and ROE as follows:

Applying Formulas Designated A & B:

A. Weighted Average Cost of Capital (WACC) =

	% Debt	**x**	**Embedded Cost of Debt**
+	**% Preferred Equity**	**x**	**Rate of Return on Preferred Equity**
+	**% Common Equity**	**x**	**Rate of Return on Regulated Common Equity**

B.

$$\textbf{Rate of Return On Rate Base (RORB)} = \boxed{\frac{\text{Invested Capital}}{\text{Rate Base}} \times \text{WACC}} + \frac{Z}{\text{Rate Base}}$$

Calculations

2003

A. **WACC** = (54.28% x 8.54%) + (1.45% x 6.31%) + (44.27% x 9.75%)

= 9.04%

B. **RORB** = $\left[\frac{\$668{,}416}{\$672{,}215} \times 9.04\% \right] + \frac{(208)}{\$672{,}215}$

= 8.96%

2004

A. **WACC** = (54.05% x 8.39%) + (1.39% x 6.31%) + (44.55% x 9.75%)

= 8.97%

B. **RORB** = $\left[\frac{\$700{,}244}{\$703{,}102} \times 8.97\% \right] + \frac{(150)}{\$703{,}102}$

= 8.91%

With respect to the calculation of WACC above, the Board has considered the various components which factor into this calculation.

In previous sections of this Decision, the Board has stated its findings with respect to the capital structure and the cost of equity (ROE).

The cost of preferred equity proposed by NP is 6.31%. The calculation of this rate is detailed in Exhibit BVP-14. This rate compares with the 6.33% cost assigned to preferred equity in Order No. P.U. 16(1998-99). The Board did not hear any evidence contesting this rate of return for preferred shares and accepts the 6.31% as the cost of preferred equity as proposed. This rate of return of 6.31% will also be used as the allowed rate of return on any regulated common equity in excess of 45%.

The embedded cost of debt proposed by NP is 8.54% for 2003 and 8.39% for 2004. The calculation of these rates are detailed in Exhibit BVP-12 (1st Revision). The Board has reviewed the evidence relating to embedded cost of debt, including the forecast short-term interest rates, and accepts the embedded cost of debt as proposed for 2003 and 2004 of 8.54% and 8.39% respectively.

NP will be required to file a revised calculation of rate base and return on rate base for test years 2003 and 2004 which reflects the decisions taken by the Board.

2. Range of Rate of Return on Rate Base

In Order No. P.U. 36(1998-99) the Board approved an increase in the range of return on rate base from 24 basis points to 36 basis points, stating at pg. 70:

> *"The introduction of an expanded range of 36 basis points will provide an incentive for the company to improve productivity and will allow for some variation in financial variables other than those adjusted by the formula."*

In this Application NP has proposed an increase in the range of return on rate base from 36 basis points to 50 basis points. According to NP the small changes in customer rates in 2000 and 2002 suggests that the range of rate of return on rate base used in the Formula is too narrow. The offsetting rate changes would not have occurred with a wider range. NP concludes that a wide range of rate of return on rate base will potentially result in greater rate stability and predictability for both NP and its customers. [Pre-filed Evidence, B. V. Perry, (1st Revision), pg. 50]

NP's cost of capital expert witnesses also supported the expansion of the range, stating that it will promote efficiency and result in less frequent rate changes. (Written Submissions, NP, Section B, pg. 11/9-12)

The Consumer Advocate does not support expanding the range to 50 basis points, stating that *"There is no verifiable evidence to show that the increased range from twenty-four basis points to thirty-six basis points provided a corresponding improvement in efficiency…."* (Final Submission, Consumer Advocate, pg. 30):

The Consumer Advocate argued that the only beneficiary was NP which benefited from additional revenue in 2000 and 2001 as a result of an expanded range of rate of return on rate base. If the range had been maintained at 24 basis points the Consumer Advocate submitted NP would have over earned in those years, and that this additional revenue would have gone into the Excess Revenue Account. (Final Submission, Consumer Advocate, pgs. 30-31)

In assessing this proposal Grant Thornton provided the following caution to the Board (Supplementary Evidence, Grant Thornton Report, pg. 7/15-18):

> *"In assessing the Company's proposal to expand the range of allowed return the Board should consider the issue in the context of the determination of the overall cost of capital. All of the factors related to rates of return and cost of capital are interrelated and none, including the range of allowed return, should be assessed in isolation."*

Grant Thornton also suggested the Board consider three additional factors in assessing the appropriateness of an expanded range of rate of return on rate base:

i) an expanded range will potentially decrease the number of rate changes and result in greater rate stability and predictability;
ii) expanding the range results in a higher upper limit for the allowed return on rate base; and

iii) the range of rate of return can provide an incentive for NP to improve productivity and generate operating efficiencies resulting in lower costs which would be passed on to ratepayers in a subsequent rate hearing.

The proposed change in the range of rate of return on rate base does not affect the determination of NP's overall revenue requirement for the test year period since the allowed return on rate base is the mid-point of the allowed range. The proposed change would result in a higher upper limit for the allowed return and for the purposes of defining the Excess Revenue Account.

In Exhibit BVP-20 (1st Revision) NP demonstrates that the proposed 50 basis point range of return on rate base is based on a 100 basis point range for rate of return on regulated common equity. In Supplementary Evidence (pg. 7/12-13), Grant Thornton stated that the current 36 basis point range for return on rate base has an implied 73 basis point range of return on regulated common equity for 2003. The Board notes that with the inclusion of deferred charges in rate base, this implied range of return on regulated common equity increases from 73 to 81 basis points. This change is not considered significant enough to warrant a change in the range of rate of return.

In the Board's view the range of rate of return on rate base can act as an incentive device to encourage NP to seek efficiencies between rate hearings, which can then be passed on to customers. This is evidenced in the operational efficiencies and cost savings that have been implemented by NP since the last rate hearing in 1998. The Board does not agree with the Consumer Advocate that only NP has benefited from the expanded range set by the Board in 1998. Ratepayers will derive the benefit for the efficiencies through lower costs, and hence lower rates into the future. The Board believes it is important to maintain the range as an incentive for NP to continue to seek efficiencies and productivity improvements in its operations.

The Board is not convinced however that a further expansion in the range from 36 basis points to 50 basis points, as proposed by NP, is warranted or necessary at this time. In the Board's view, while there are opportunities for future operating efficiencies, the Board feels that the existing range of 36 basis points has served both NP and ratepayers well over the period of operation of the Formula and should be maintained.

The Board will approve a range of 36 basis points for the rate of return on rate base for test years 2003 and 2004 and for use with the Formula, unless otherwise ordered by the Board.

VIII. ACCOUNTING TREATMENT AND POLICIES

1. Amortization of Recovery of Balance in Weather Normalization Reserve

The Weather Normalization Reserve is a combination of two reserves: Degree Day Normalization Reserve and Hydro Production Equalization Reserve. The Degree Day Normalization Reserve normalizes the company's revenue and purchased power costs for annual variations in weather conditions. The Hydro Production Equalization Reserve normalizes the company's purchased power expense for annual variations in normal stream-flows to its hydro plants.

The balances in the Weather Normalization Reserve are filed with and approved annually by the Board. The balance in the reserve owing from customers as at December 31, 2001 is outlined below [Pre-filed Evidence, B. V. Perry, (1st Revision), pg. 62]:

Weather Normalization Reserve Balance as at December 31, 2001 ($millions)	
Hydro Production Equalization Reserve	9.4
Degree Day Normalization Reserve	0.5
Total	**9.9**

While the degree day variations have been observed to be approximating zero over time, the balance in the Hydro Equalization Reserve owing from customers has been increasing since 1987 and is at $9,400,000 at the 2001 year end. The following table provides a breakdown of this balance for each contributing factor [Pre-filed Evidence, B. V. Perry, (1st Revision), pg. 65]:

Breakdown of the 2001 Hydro Production Equalization Reserve Balance ($millions)	
Increase in purchased power mill rate	4.9
Decrease in Income Tax Rate	0.7
Variation from Normal Stream Flows	3.8
Total	**9.4**

In Order Nos. P.U. 9(2001-2002) and P.U. 2(2002-2003) the Board ordered "*At the next general rate review, the function and methodology of the Weather Normalization Reserve will be reviewed by the Board whereby the Applicant shall present its views on the function and methodology of the reserve and its proposal for the disposition of the deficit balance contained in the reserve account.*" This issue was reviewed as part of this hearing. While NP has not proposed any changes in the function and methodology of the reserve account, NP does propose to recover the portion of the weather normalization reserve that is not expected to reverse over time.

NP states that the reserve balance of $5,600,000 resulting from increases in the purchased power mill rate ($4,900,000) and the income tax rate ($700,000) is not expected to reverse over time. For this reason NP is proposing to amortize the recovery from customers of the $5,600,000 balance in the Hydro Production Equalization Reserve ($8,700,000 pre-tax) over 5 years beginning in 2003. The amortization for the period 2003 through 2007 increases purchased power expense by approximately $1,700,000 in each year.

NP commissioned a Water Management Study in 2000 and, based on the recommendations of this study, adjusted its annual normal production levels for the purposes of calculating transfers to or from the Hydro Production Equalization Reserve. As recommended in the study, NP is also proposing a further review of normal hydro production levels and reserve balances in 2005, and every five years thereafter. This review will include a review of the mill rate and the income tax rate changes so that any necessary adjustments can be put to the Board for approval.

NP states that, as a result of its review, the Degree Day Normalization reserve is working as intended and no changes or necessity for further review are proposed.

NP's expert accounting witness, Mr. J. T. Browne, provided evidence as to whether NP's proposed treatment of the non-reversing portion of its Hydro Production Equalization Reserve is consistent with established regulatory principles. (Pre-filed Evidence, J.T. Browne, <u>Accounting and Regulatory Issues Related to Future Employee Benefits and the Hydro Production Equalization Reserve, October 11, 2002</u>, pgs. 15-16) Mr. Browne stated that the reserve represents a cost of providing regulated service and that, according to the cost of service standard, NP should have a reasonable opportunity to recover the balance through allowed rates, including the non-reversing amounts. He also stated that the issue is in what period should it recover the non-reversing amounts. Mr. Browne provides the following opinion on the recovery period at pg. 15 of his report:

> *"With the information now available, the non-reversing amount represents costs of providing service in previous periods. Since it is not possible to adjust past rates, it would normally be appropriate to recover the balance through rates over as short a period as is reasonable, such as a period within three to five years. However, the non-reversing amount was built up over a period of 30 years. Therefore the principle of intergenerational equity is not as applicable as it might otherwise be. As a result, it is reasonable to place more of an emphasis on smoothing the impact of the amortization on rates, consistent with the principle of rate stability and predictability. An amortization period of five years achieves this. Accordingly, a five-year amortization is appropriate".*

Mr. Browne concludes that NP's proposed treatment of the non-reversing portion of its Hydro Production Equalization Reserve is consistent with established regulatory principles.

In written submission (pg. 80-81) the Consumer Advocate cautioned the Board "*to rely on its own view of intergenerational equity*" when determining the length of time over which the outstanding balance should be recovered. Although not explicitly stated the Board takes from the Consumer Advocate's submission that a longer recovery period is preferable. A longer recovery period would reduce the revenue requirement in each year.

Grant Thornton reviewed NP's proposals with respect to the Hydro Production Equalization Reserve and found the proposals reasonable. Grant Thornton also agrees that the disposition of the $5,600,000 outstanding balance that will not reverse over time is appropriate at this time. The proposed amortization period of five years was seen as reasonable and in line with amortization periods used for prior balances, such as the amortization of the change in GEC from full cost accounting to incremental, and the true-up variance from the 1996 Gannett Fleming depreciation study. The impact on rates is also minimized as compared to a shorter recovery period such as three years. The impact on revenue requirement is $1,120,000 for a five-year amortization period as compared to $1,870,000 for a three-year recovery period. (Grant Thornton Report-NP 2003 GRA, pg. 6/7-9)

The Board is satisfied that NP's proposal to amortize the recovery of the non-reversing portion of the Reserve is reasonable and will address in part some the concerns raised in Order No. P.U. 9(2001-2002). With respect to the appropriate amortization period the Board accepts that five years is a reasonable recovery period which will allow NP to recover its costs while minimizing the impact on consumers. The Board is reluctant to extend recovery of any outstanding balance longer than necessary. The Board also accepts NP's proposal to review the balance in the reserve at the end of each five-year period and identify any non-reversing amounts. The timing of this review will coincide with the recovery period for the current outstanding balance approved in this Decision.

The Board will accept NP's proposal to amortize the recovery of the $5,600,000 balance in the Hydro Production Equalization Reserve over a period of five years, beginning in 2003. NP will be required to review the balance in the Hydro Production Equalization Reserve as of December 31, 2005 and to apply to the Board for an Order as to the disposition of outstanding balances, positive or negative, as part of its next general rate application.

2. Adjustments to Pension Accounting

NP currently uses the fair market method to value pension assets for the purposes of determining pension expense. NP has proposed to adopt the market-related method on a prospective basis beginning on January 1, 2003. NP states the basis for using the market-related value approach to calculate expected return on pension plan assets is to create a smoothing impact on its pension expense. NP also submits that the use of a three-year moving average provides a rational and systematic manner to recognize the pension expense and reduces the volatility of that expense caused by changing market conditions.

Grant Thornton reviewed NP's proposal and found that the pension accounting changes as proposed are reasonable and in accordance with Section 3461 of the CICA Handbook and with Generally Accepted Accounting Principles (GAAP). The move to a market-related approach will reduce pension expense in 2003 from $4,500,000 to $3,300,000, and in 2004 pension expense will be reduced from $3,600,000 to $3,400,000. (Grant Thornton Report-NP 2003 GRA, pg. 6/38-43) This results in lower revenue requirement, and therefore lower rates.

NP is proposing to adopt this approach on a prospective basis beginning January 1, 2003 rather than on a retroactive basis. NP submits that this approach is consistent with other accounting policy changes previously approved by the Board. For example, in Order No. P.U. 17(1987) the Board approved the adoption of the CICA recommendations on pension accounting on a prospective basis. [Pre-filed Evidence, B. V. Perry, (1st Revision), pg. 68/4-5]

The Board will approve NP's proposal to adopt the market-related method of determining pension expense on a prospective basis, effective January 1, 2003.

3. Depreciation Accounting

i) Depreciation Study Update

In Order No. P.U. 7(1996-97) the Board ordered NP to submit its next depreciation study in 2001. On December 14, 2001 NP filed with the Board a depreciation study prepared by Gannett Fleming Valuation and Rate Consultants, Inc. (*"Gannett Fleming"*) based on plant in service as at December 31, 2000. The service life analysis performed by Gannett Fleming in the 2001 study resulted in a reduction in the depreciation rates recommended for Distribution, Transmission, Substation and Transportation equipment. The study also provided a comparison between the accumulated depreciation recorded by NP with respect to plant in service as of December 31, 2000 and a calculated reserve based on the new depreciation rates recommended. The actual reserve variance as of December 31, 2000 was calculated by Gannett Fleming at $5,100,000. [Pre-filed Evidence, B. V. Perry, (1st Revision), pg. 55/20-22]

In addition to the change in depreciation rates, Gannett Fleming recommended that NP adopt the mid-year convention for book depreciation practices. NP had historically calculated annual depreciation expenses using the full year convention, which assumes all property is in service for twelve months in the year it is installed. This results in a full year of depreciation recorded for current year's additions. The mid-year convention assumes that all property is installed on July 1 of each year, so that only a half-year of depreciation expense is recorded for current year's additions. Based on Gannett Fleming's recommendation NP adopted the mid-year convention in 2001, resulting in a reduction in depreciation expenses for 2001 of approximately $900,000 in that year. [Pre-filed Evidence, B. V. Perry, (1st Revision), pg. 56/11-13]

As part of this Application NP filed an updated depreciation study, also completed by Gannett Fleming. This study reflects changes in plant in service as at December 31, 2001 and also includes, as part of the plant in service, the joint use poles purchased from Aliant. In addition Gannett Fleming calculated the accumulated reserve variance as at December 31, 2001 based on the mid-year convention for book depreciation as adopted by NP in 2001. In the updated study Gannett Fleming recommended that NP record the joint use poles purchased from Aliant using original cost and accumulated depreciation. Gannett Fleming also recommended that NP continue to use the straight-line equal life group method that it has been using for a number of years for its plant assets with the exception of certain General and Communication accounts.

The Consumer Advocate did not raise any specific objections to the recommendations of the 2002 Depreciation Study as proposed by NP to be adopted on a prospective basis. In written submission (pg. 80) the Consumer Advocate argued that, if NP had adopted the recommendations of the 2001 Gannett Fleming Study in 2002, NP's revenue requirement for that year could have been reduced by $5,800,000. The Consumer Advocate submits that this contributed to NP's higher ROE return in 2002.

Grant Thornton reviewed the 2002 Updated Depreciation Study and confirmed that the results and recommendations of the study have been incorporated into NP's depreciation estimates for 2003 to 2004. Grant Thornton also confirmed that the use of the half-year rule for calculating depreciation on net capital additions is very common practice and is in compliance with generally accepted accounting principles. (Grant Thornton Report-NP 2003 GRA, pgs. 11-12)

The Board has reviewed the submissions and evidence regarding the Depreciation Study and accepts the recommendations of the study. The Board does not accept the Consumer Advocate's submission that adoption of the study in 2002 would have reduced NP's revenue requirement. The Board considers the issue of revenue requirement as part of its consideration of test year expenses in a general rate hearing. Adoption of any of the recommendations outside a test year period would not have affected rates to consumers, whether the impact was positive or negative.

The Board will approve the 2002 Depreciation Study as filed. The depreciation rates as recommended in the Depreciation Study will be approved for calculating depreciation expense for the test year period 2003 and 2004

ii) Reserve Variance Adjustment

Gannett Fleming has calculated the accumulated reserve variance as at December 31, 2001 based on application of the mid-year convention. This results in an increase in the reserve variance from $5,400,000 as at December 31, 2000 to $17,200,000 as at December 31, 2001. Gannett Fleming has recommended that where the reserve variance exceeds 5% on an individual account basis, the accumulated reserve variance for that account be amortized over the account's composite remaining life. This would result in a reduction of depreciation expense (*"true-up"*) of $1,200,000 in each of the next five years, and would still result in accumulated reserve variances not being fully amortized. This approach was also recommended by Gannett Fleming in the 1996 Depreciation Study. In Order No. P.U.7 (1996-97) the Board determined that from the perspective of correcting a depreciation estimate every five years (based on the time frame between depreciation studies) the amortization of the accumulated reserve variance over five years has the quality of intergenerational equity. If a 5-year amortization period is used for the true-up, depreciation expense is reduced by $3,500,000 in each of the next 5 years. [Pre-filed Evidence, B. V. Perry, (1st Revision), pgs. 58-59]

In this Application NP is proposing that the reserve variance in excess of 5% be amortized over a three-year period 2003-2005, resulting in a depreciation expense reduction or *"true-up"* of $5,800,000 in each of these years. NP states that the three-year amortization period coincides with the next depreciation study expected in 2006, based on plant in service as of December 31, 2005 and is consistent with the Board's view on intergenerational equity expressed in Order No. P.U. 7(1996-97). This approach also reduces the costs borne by NP's customers for that period. [Pre-filed Evidence, B. V. Perry, (1st Revision) pg. 60] Based on NP's proposal the amount of $5,800,000 has been used to reduce NP's revenue requirement in each of 2003 and 2004.

While the Board adopted a five-year amortization period for the depreciation expense true-up in 1996, NP's proposal in this Application to use a three-year recovery period reduces expenses for the test year period and results in lower costs to be recovered from consumers. The Board agrees with NP that this proposal is consistent with the principle of intergenerational equity.

The Board will approve NP's proposal to amortize the depreciation reserve variance over the three-year period 2003-2005.

4. Accounting Treatment for Other Employee Future Benefits

NP's other employee future benefits, other than pensions, include retirement allowances to qualifying employees and the cost of health, medical and life insurance for retired employees. These expenses are currently recognized by NP on a cash basis. The current costs for health, medical and life insurance for retired and current employees is estimated to be $1,400,000 in each of 2003 and 2004, of which approximately 75% is charged to operating expenses. The cost of retirement allowances in 2003 and 2004 is estimated to be $200,000. These costs are tax deductible in the year they are incurred [Pre-filed Evidence, B. V. Perry, (1st Revision), pg. 71]

Section 3461 of the CICA Handbook recommends the use of the accrual method of accounting for other employee future benefits effective January 1, 2000. The accrual method requires the financial statements to reflect the estimated cost incurred during the financial reporting period.

NP states that adopting the accrual method of accounting for these benefits would represent a change in accounting policy for the company. In Exhibit BVP-25 (1st Revision) NP compares the current cost of its employee future benefits and the estimated accounting expense for these benefits if the company adopted the CICA recommendations. According to this Exhibit a change to accrual accounting for other employee future benefits will result in a $4,100,000 increase in revenue requirement for 2003, including additional income tax of $1,500,000.

As a result of the impact of moving to the accrual method NP is proposing to continue to account for employee future benefits on a cash basis. NP also states that it will continue to monitor this obligation and corresponding regulatory practice and that it may propose to recover these costs on an accrual basis in the future.

NP's accounting expert witness, Mr. J.T. Browne, provided the following opinion on this issue (Pre-filed Evidence, J.T. Browne, <u>Accounting and Regulatory Issues Related to Future Employee Benefits and the Hydro Production Equalization Reserve, October 11, 2002</u>, pg. 10):

> "*NP is not following Section 3461 in accounting for its OFEBs and what GAAP would normally require. However, as long as it is reasonably expected that rates will produce sufficient additional revenue to cover the cost of the future employee benefits in rates when payment is required and such rates will be chargeable and recoverable from customers, NP's accounting policy for its OFEBs is in accordance with GAAP. If the Board approves NP's proposal to continue with the pay-as-you-go method for rate setting purposes, it is likely that the above conditions will be met and NP's accounting policy for its OFEBs will be in accordance with GAAP.*"

In addressing the question of whether NP's treatment of employee future benefits for rate setting purposes is consistent with established regulatory practice, Mr. Browne concludes at pg. 13 of his report that:

> *"From the perspective of the principle of intergenerational equity, the accrual method for recovering OFEB costs is preferable to the pay-as-you-go method proposed by NP. However, the NP proposal is a practical approach that recognizes the impact of dealing with the transition from one method to the other".*

Grant Thornton also reviewed NP's proposal and concluded that NP's proposal of using the cash basis for accounting for other future employee benefits is acceptable. (Grant Thornton Report-NP 2003 GRA, pg. 8/1-2)

In addressing this proposal the Board is cognizant of the fact that in Order No. P.U. 7 (2001-2002) it approved NLH's proposal to adopt the accrual method of accounting for other employee future benefits in accordance with GAAP. However as part of its proposal, NLH did not propose to recover from ratepayers the actuarial accrued balance of other employee future benefits of $21,200,000, proposing instead to write-off this balance against prior period earnings. In the case of NP the additional cost to ratepayers of moving to the accrual method is in the order of $4,100,000 in each of 2003 and 2004. To avoid rate impact on consumers the Board is prepared to accept NP's proposal to continue with using the cash basis for recognizing expenses for other employee future benefits.

The Board is concerned about the potential liability for employee future benefits and is of the view that NP should explore using the accrual method of accounting for these benefits. The Board recognizes that there are significant transitional obligations associated with this change in accounting policy but once the transitional obligation has been met these costs should decrease. NP should continue to monitor its obligations with respect to employee future benefits and corresponding regulatory practice. The Board will direct NP to propose a plan at its next general rate application for moving towards the accrual method of accounting for employee future benefits as recommended by CICA. The Board emphasizes such a plan should be presented to the Board as an alternative to the existing method and should address the transitional impact with a view to fulfilling NP's obligation to its employees while at the same time moderating its impact on rates. The Board will then be in a position to consider this alternative accrual method and its specific impacts at the next hearing.

The Board will approve NP's proposal to continue using the cash basis for recognizing expenses for other employee future benefits. With its next general rate application, NP will be required to submit a report which addresses the use of the accrual method as an alternative to the existing accounting treatment for other employee future benefits.

5. Amortization of Regulatory Costs

NP is proposing to amortize over a three-year period the estimated external costs of $1,200,000 associated with the public hearing of this Application. This results in a recovery of $400,000 per year for each of the next three years. This proposed treatment of hearing costs is similar to that approved by the Board in Order No. P.U. 36 (1998-99) following NP's 1998 General Rate Proceeding. In that Order the Board approved amortization of external hearing costs of $1,150,000 over a three-year period commencing in 1999.

Grant Thornton has reviewed NP's proposal and concludes that the proposal is reasonable. According to Grant Thornton the deferral of such costs is intended to better match the costs of major proceedings over the intervening period and also smoothes the effect on NP's cost of service, which is advantageous to the consumer.

The Consumer Advocate and NLH did not raise any issues with this proposal. The Board accepts the proposal as reasonable and consistent with past regulatory practice.

The Board will approve NP's proposal to amortize over a three-year period, beginning in 2003, the estimated regulatory costs of $1,200,000.

6. Disposition of Excess Revenue Account – 2001 Excess Earnings

In Order No. P.U. 29(2001-2002) the Board approved the following definition of the Excess Revenue Account:

> *"This account shall be credited with any revenue in excess of the upper limit of the allowed range of return on rate base as determined by the Board. Disposition of any balance in this account shall be as determined by the Board. For 1998 all earnings in excess of 9.99% rate of return on rate base, for 1999 all earnings in excess of 10.16% rate of return on rate base, for 2000 and 2001 all earnings in excess of 10.46% rate of return on rate base, and for 2002 and subsequent years all earnings in excess of 10.24% rate of return on rate base shall, unless otherwise ordered by the Board, be credited to this account."*

In 2001 NP earned excess revenue of $944,000 over the upper limit of the allowed range of return on rate base of 10.46% as set by the Board for 2001. This amount was reported by NP to the Board in Return 10A of its 2001 Annual Report to the Board. As required this amount was set aside in the Excess Revenue Account to be disposed of as determined by the Board. In this Application NP is proposing to apply this excess revenue to reduce the revenue requirement equally for 2003 and 2004 ($472,000 in each year), which will in turn result in lower rates to customers over this period. [Pre-filed Evidence, B. V. Perry, (1st Revision), pg. 74/6-8]

Grant Thornton reviewed NP's proposal and concluded that NP's proposed approach was reasonable and that ratepayers will receive full recovery of the $944,000 over the two-year period 2003 and 2004 (Grant Thornton Report-NP 2003 GRA, pg. 9/13-15). Grant Thornton also addressed the option of rebating the amount directly to consumers, as was approved by the Board in dealing with the disposition of the 2000 excess earnings of $6,500,000. Grant Thornton points out that, since NP is requesting a rate increase in this Application, rebating the excess earnings to consumers would result in a higher increase in rates being requested for 2003. As well the magnitude of the 2001 excess earnings is considerably less than it was for the 2000 excess earnings and hence the impact on consumers would be significantly less.

During the hearing the Consumer Advocate raised the issue of the appropriate disposition of the Excess Revenue Account, suggesting that any amounts in the Excess Revenue Account should be rebated to consumers forthwith. (Transcript, April 8, 2003, pg. 88/14-22 and pg. 89/6-12) The Consumer Advocate also suggested that NP's handling of the Excess Revenue Account disposition during its rate filing was not transparent and was confusing to consumers.

The Board is satisfied that NP has acted properly and in compliance with Board directives with respect to the Excess Revenue Account, and in particular in relation to the disposition of the existing balance. The Board approved the existing definition of this Account in Order No. P.U. 29(2001-2002) and NP has properly credited this account in 2001 with earnings above the 10.46% rate of return on rate base, as required. The Board has the authority and discretion to determine the disposition of this Account and the Board will exercise this discretion in this Decision.

As a result of the Board's finding in this Decision on the ROE to be used in setting the rate of return on rate base, the Board expects that there will be a decrease in revenue requirement for the test year period. As a result NP's proposal to apply the 2001 excess earnings against the increased revenue requirement to minimize the rate increase is no longer valid. In the Board's view the appropriate disposition of this account would be to rebate the excess earnings to customers.

The Board finds that the 2001 excess earnings of $944,000 should be rebated to customers. NP will be required to submit a proposal for this rebate as part of its filing of revised rates.

7. 1992-1993 Excess Earnings

In Order No. P.U. 36(1998-99) the Board determined that there were excess earnings in 1992 and 1993 totalling $1,908,000 on an after tax basis. The Board ordered "*The amount of $1,908,000 which is the total of the after tax excess earnings for 1992 and 1993, be established as a component of common equity on which no return will be allowed for the period 1999-2003. The total amount to be recovered is $954,000, which represents one-half of the after tax excess earnings, and a review will take place before the end of the year 2003 as to the disposition of any outstanding amount.*"

Since 1999 NP has been complying with this Order and, up to 2002, has recovered $715,118 of the total $954,000, leaving $238,882 remaining to be recovered. [Pre-filed Evidence, B. V. Perry, (1st Revision) pg. 85] The amount of $715,118 recovered from 1999 to 2002 represents a reduction in revenue from rates and savings to ratepayers of $1,233,000 over this period.

NP is proposing to recover the outstanding amount over the two-year period 2003-2004, by adjusting rates as of August 1, 2003 to give a prorated recovery based on energy sales from

August 1 to December 31, 2003. The effect of this adjustment would be a total recovery of $112,000 in 2003 and $335,000 in 2004, for a total recovery of $447,000, including income tax effects. [Exhibit BVP-28, (1^{st} Revision)]

Grant Thornton reviewed NP's proposal and concluded the approach was reasonable and achieves better than full recovery for ratepayers over the two-year period. (Grant Thornton Report-NP 2003 GRA, pg. 10/32-34)

The Board will accept NP's proposal for adjusting 2003-2004 revenue requirement to recover the outstanding amount of the 1992-1993 excess earnings as required by Order No. P.U.36(1998-99), subject to any adjustments arising from this Decision.

8. Deferral of Certain Outstanding Issues

i) Revenue Recognition Study

NP has asked the Board for approval to defer dealing with the outstanding issues relating to the revenue recognition study and the Unbilled Revenue Increase Reserve Account pending resolution of an outstanding dispute with the Canada Customs and Revenue Agency (CCRA). The dispute deals with NP's current policy of revenue recognition and an associated income tax reassessment by CCRA.

NP has always recorded revenue as customers are billed whereas CCRA's position is that NP is required to report its revenue on the accrual basis. NP maintains that it is recording revenue in accordance with Board Orders. The issue relates primarily to the billings and associated revenue for electrical consumption for the last two weeks of the year, for which bills are issued after December 31. The revenue for those two weeks is approximately $20,000,000, before taxes. (Transcript, April 9, 2003, pg. 5/2-25; pg. 6/1)

In Order No. P.U. 36(1998-99) the Board ordered NP to file a revenue recognition study with the Board before its next general rate application or by March 31, 2000, whichever is earlier. The Board later amended this Order by deleting reference to March 31, 2000 and substituting the words *"at such time to be determined by the Board."*

NP submitted that the filing of a revenue recognition study at this time could potentially prejudice its position with respect to its dispute with CCRA over the Income Tax Reassessment. According to NP if it were to lose this dispute it would mean a liability of approximately $14,400,000, of which 50% has already been deposited with CCRA. This liability would have to be recovered through electricity rates.

The Consumer Advocate questioned NP's company witness, Mr. Perry and Mr. Brushett of Grant Thornton, the Board's Financial Consultant, on this issue. In response to a question from the Consumer Advocate on the revenue impact to NP of using the accrual method to recognize revenue, Mr. Brushett testified: (Transcript, April 9, 2003, pg. 6/12-25)

A. From an accounting point of view, you're correct in that there would be additional revenue recognized offsetting an expense that would have to be recognized. But just so that the record's clear and the Board understands, there's no extra revenue. There will be no extra cash coming in. It's a timing thing. This is revenue that, under an accrual method, would be recognized in December instead of being recognized in January. So it's no extra cash available to pay it as such but it is, from an accrual accounting point of view, the timing of recognition, yes, one would offset the other.

The Consumer Advocate's position on this issue was set out in final submission (pg. 79):

"If, as it appears, there is no detriment to consumers by changing to the accrual method advocated by CCRA no further expenditures should be made from regulatory funds in reference to this issue. If NP's shareholder wishes to proceed with the case for reasons best known to itself, the cost of financing this case, together with interest and penalties, should come from non-regulated funds or be supported entirely by NP's shareholders."

The Board has outlined its position with respect to the revenue base and the revenue recognition policy of NP in Order No. P.U. 36(1998-99). The Board accepts NP's position in this proceeding that any further consideration of this issue at this time may prejudice the outcome of its current dispute with CCRA with respect to the Income Tax Reassessment relating to revenue recognition. The Board does not agree with the Consumer Advocate that NP's pursuit of this issue with CCRA is not beneficial to ratepayers. Resolution of the issue will provide certainty to the Board and NP on a go forward basis. The Board will deal with any issues arising from the final decision of the tax case, including any potential liabilities or benefits to ratepayers, once the case has been resolved.

The Board will approve NP's request to defer dealing with the outstanding issues relating to the Revenue Recognition Study pending resolution of the dispute with CCRA.

ii) Unbilled Revenue Increase Reserve Account

In Order No. P.U. 36(1998-99) the Board established an unbilled revenue increase reserve account to record the difference between recognizing revenue based on the two differing revenue recognition policies and the difference arising from a delayed implementation of an approved rate increase from January 1, 1999 to February 1, 1999. The Board ordered that the disposition of this account be dealt with after the revenue recognition policy has been fully reviewed at a public hearing.

Since the Board has agreed to the deferral of the issues relating to the Revenue Recognition Study until the dispute between NP and CCRA is resolved, the Board will also approve NP's request to defer dealing with the disposition of the unbilled revenue increase reserve account. This issue will be dealt with as part of the Order arising from consideration of the Revenue Recognition Study to be filed by NP, as was intended in Order No. P.U. 36(1998-99).

9. Accounting for Early Retirement Programs

The Consumer Advocate raised the issue of NP's accounting treatment of early retirement programs. In 1999 NP applied to the Board for approval to amortize and fund pension liability over an extended period, which was approved in Order No. P.U. 24(1999-2000). However in 2000 and 2001 early retirement programs were funded and expensed in those years. The Consumer Advocate argues that this *"uneven treatment of such an expense can lead to consumers losing out on a fair opportunity to share in NP's excess revenue if in that year NP manages to over-earn on its ROE but stays within its range of return on rate base, based on NP's interpretation of the Stated Case."* (Final Submission, Consumer Advocate, pg. 81) The Consumer Advocate recommends a 10-year amortization for early retirement programs.

NP's position on this issue is stated below [Pre-filed Evidence, B. V. Perry (1st Revision, pg. 69/11-16]:

> *"CICA recommendations provide that the cost of early retirement programs be recorded in the current period. When the forecast cost of any retirement program is so large that recognition of the costs in one accounting period will have a material negative impact on Newfoundland Power's financial position in that particular year, the Company has applied to the Board to deviate from CICA recommendations and amortize the early retirement program costs over a period of years."*

On questioning by Board Hearing Counsel Mr. Perry described NP's approach to deciding how to expense an early retirement program:

> A. ….I think when we assess the financial operations of the Company and make our decision whether to come before the Board, that's a management assessment, you know, we're at the point in the year when we're prepared to offer the program, can we expense it right away, get the cost out of the way immediately and not come before the Board based on our judgement of what the financial results are, I think that's management, you know, it's strictly management, so I believe it's working the way it is right now, and I think the Company has proven that its approach on early retirement programs are doing very good and it's been probably the biggest tool we've had to cut costs in our operations. So I'm not certain it's one that we should tinker with.
> (Transcript, March 11, 2003, pgs. 152-153/14-6)

Mr. Brushett of Grant Thornton was also questioned on this issue by the Consumer Advocate. When asked about the impact of expensing the early retirement programs in 2000 and 2001, both years when NP had excess earnings, Mr. Brushett stated:

> A. That's correct. In those two years, had there been a decision to defer and amortize, there would have been additional excess earnings. But I guess the other consideration that the Board would have to look at here is that the costs would be recovered from rate payers at some point. It's just a matter—what we're talking about now is the timing. So are they charging off in those years, in years when, for lack of better terminology, you know, they can be absorbed. They do reduce, hypothetically, a rebate that might otherwise go back to consumers, but that would be giving them a cheque today and taking it back from them in 2004, 5, 6, 7 and 8. So it's really what we're talking about is timing, and I think those are the issues that the Board would have to consider. At the end of the day, the total cost of these amendments to the pension plan and the cost of the early retirement programs would be recovered from rate payers. It's just a matter of can you absorb it in those years or-

Q. Sure. And I'm not denying that they would be recovered, I'm just wondering what the timing is and shouldn't that be some consistent policy.

A. So under the scenario that you're suggesting, you know, might have resulted in a rebate in those years, but then rates would be higher next year and the year after and so on as a result of that. So that's I guess the considerations that the Board would have to take into account in assessing it.

The Board agrees with NP that the decision to offer early retirement programs and the accounting treatment of those programs is a management issue and that CICA guidelines should apply in the first instance. If the impact on the financial position of NP of expensing the costs as required by CICA is material then NP would either have to not offer the program or apply to the Board to recover those costs over a period of time. The costs for the 2000 and 2001 early retirement programs were not recovered in rates and, now that the programs have been expensed, will not be required to be recovered in future rates. Consumers are also benefiting on a go forward basis from the lower operating costs resulting from reduced labour expenses. While amortization of the 2000 and 2001 programs may have resulted in higher excess earnings, amortization would also mean that those costs would now be incorporated into rates for recovery. The Board agrees with Mr. Brushett that, from a consumer perspective, it's an issue of timing and that ultimately the total costs of any program would be recovered.

The Board accepts NP's treatment of expenses associated with the 2000 and 2001 early retirement programs.

IX. REVENUE REQUIREMENT

1. Test Year

Section 3(a)(ii) of the *EPCA* states:

"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…

(ii) should be established, wherever practicable, based on forecast costs for the supply of power for 1 or more years."

NP's proposals for revenue requirement and resulting rate changes are based on test years 2003 and 2004. It has been the practice of the Board to utilize forward-looking test year costs for a single year. The 1998 hearing utilized forecast costs for 1999 as the test year for the purpose of setting rates and also for implementing the automatic adjustment formula.

The issue of the use of a 2003 and 2004 test year period was canvassed by Board Hearing Counsel in cross examination of Mr. Perry (Transcript, March 13, 2003, pg. 79/81):

Q. Mr. Perry, we'll start with a general question, if you will, in a number of instances in the application, Newfoundland Power is asking for the Board's approval of accounting treatments or rates of return or the fixing or determining of forecast rate base for both fiscal year 2003 and fiscal year 2004. And I'm wondering if you could tell us whether, from a Company's perspective, do we have a 2003 test year that the Board's dealing with or a 2004 test year or are both test years from the power company's perspective?

A. Commissioners, we've had some debate on this, I guess, internal to the Company, but essentially we're looking at both years. We believe that by the time we get through the hearing and we receive the order of the Board we're going to be halfway through this year probably. So we feel that brings in 2004 as the year that will see the full impacts of the Company's proposals and the Board's order. So, we felt that it made sense if we could put together a proposal that carried us through both years and that's how we see it.

Q. So, you see 2004 as a test year, then?

A. Yes, I guess I would say that, Mr. Kennedy, you know, essentially, it's – we're looking at the two-year period as what we've put before the Board as being, you know, what the Company believes is sufficient to carry it through to the end of 2004…

None of the other parties took a position on the issue of the test year.

The Board accepts NP's reasoning for proposing a test year period to cover 2003 and 2004. Many of the proposals for deferred costs and amortization of recoveries have been spread over the two-year period. If the Board were to adopt a test year of 2003 along with an automatic adjustment formula, the Formula would have to be used in the fall of 2003 to set rates for 2004, which could result in two rate adjustments within a relatively short time frame.

The Board will use fiscal years 2003 and 2004 as the test years for determining revenue requirement, as proposed by NP.

2. Test Year Revenue Requirement

Revenue requirement is the sum of the required return on rate base, depreciation and total operating costs to be recovered from consumers in rates. Total operating costs include purchased power, income taxes and operating expenses.

NP's proposed revenue requirement is shown below: [Exhibit BVP-26 (1st Revision); Pre-filed Evidence, B. V. Perry, (1st Revision), pg. 83]

Summary of Proposed 2003 and 2004 Revenue Requirement ($000s)		
	2003	**2004**
Purchased Power	226,499	229,941
Operating Expenses	51,837	52,434
Depreciation Expense	29,234	30,589
Income Taxes	16,644	16,983
Return on Rate Base	63,209	65,668
	387,423	**395,615**
Deductions:		
Other Revenue	(7,787)	(8,593)
2001 Excess Revenue	(472)	(472)
Non-Regulated Expenses (Net of Tax)	(725)	(725)
Revenue Requirement from Rates[1]	378,439	385,825
Revenue from Existing Rates[2]	377,237	82,193
Required Increase in Revenue from Rates	**1,202**	**3,632**

[1] Before adjustment for 1992-1993 Excess Earnings (See pg. 86 of this Decision).

[2] Rates as approved by Order No. P.U. 29 (2001-2002) as adjusted for RSA and MTA in Order No. P.U.22 (2002-2003) and continued as interim rates under Order No. P.U. 35 (2002-2003)

The following expenses comprising NP's proposed revenue requirement are reviewed by the Board:

i) Purchased Power

Purchased power expense is the largest of NP's expenses in providing electrical service and accounts for almost 59% of NP's gross revenue requirement. Estimates of purchased power expense depends on the forecast energy sales and the rate charged to NP by NLH for electricity purchased by NP. Purchased power expense is affected by the operation of the Weather Normalization Reserve, as discussed on pgs. 77-79 of this Decision, and elasticity impacts due to the proposed rate increase.

The forecast purchased power expense includes an amount of $1,700,000 in each of 2003 and 2004 due to the amortization of the balance in the Weather Normalization Reserve. A reduction of $100,000 in 2003 and $300,000 in 2004 is applied to account for elasticity impacts.

The Board has accepted NP's forecast of customer growth and energy sales for the test year period as described on pg. 29 of this Decision. These forecasts, along with the wholesale rate charged by NLH, form the basis for the purchased power expense. If the wholesale rate charged by NLH for purchased power changes as a result of NLH's general rate application to the Board, NP will apply for an increase in rates to account for this increased expense.

The Board accepts the purchased power expense for the test year period 2003-2004, as proposed by NP, subject to any adjustments arising from this Decision.

ii) Operating Expenses

Operating expenses account for approximately 13% of NP's total revenue requirement in each of 2003 and 2004. These expenses include labour costs, which account for over 50% of the total operating expenses, vehicle expenses, materials, travel, telecommunications, tools and clothing allowances, insurances, equipment rental and maintenance, vegetation management, and other similar types of expenditures.

NP can exercise some control over operating costs and this area is where NP has focused most of its effort in finding efficiencies and minimizing costs.

Over the period 1998 to 2003, NP's gross operating expenses are expected to remain relatively stable, ranging from $55.4 million in 1998 to a forecast of $54.5 million in 2004. [Pre-filed Evidence, E. A. Ludlow, (1st Revision), pg. 6/7-9] Over the same period the number of customers and NP's total sales will have increased by 4.9% and 10.8% respectively. On a per customer basis, gross operating expenses are forecast to decrease over the period by 7%, compared to forecast inflation of 11.9%. (Pre-filed Evidence, E. A. Ludlow, pg. 7/6-10)

The operating expense forecasts for the test year period 2003-2004 have been adjusted to account for the deferral and amortization of regulatory costs and the move to a market-related value for calculating pension expense, as shown below [Pre-filed Evidence, B. V. Perry, (1st Revision), pg. 81]:

Proposed Operating Expenses: 2003-2004 ($millions)		
	2003	**2004**
Operating Expense Forecast	54.1	52.5
Deferral of Regulatory Costs	(0.8)	0.4
Pension Expense Changes	(1.5)	(0.5)
Proposed Operating Expense Forecast	**51.8**	**52.4**

The adjustments for regulatory costs and pension expense changes are discussed in detail on pg. 84 and pgs. 79-80 this Decision.

The majority of the proposed operating expenditures were not contested in the hearing. The primary area challenged by the Consumer Advocate was the level of executive compensation and the Board will deal with this area separately.

As a result of Order No. P.U. 7(1996-97), NP has been filing with the Board annually its Advertising and Marketing Report the purpose of which was to detail objectives for the year as well as quantative measures of success and a description of advertising efforts. Since 1997 the Board's Financial Consultants have included in their annual review of NP a report on its advertising and marketing expenses. Over that period they have consistently reported that nothing has come to their attention that would indicate that NP is not in compliance with Order No. P.U. 7(1996-97).

The Board will continue to instruct its Financial Consultants as part of their annual financial review of NP to report on advertising and marketing expenditures of the Company to ensure that these expenditures meet the criteria established in Order No. P.U. 7(1996-97). However, the Board feels that the annual filing of a separate report is no longer necessary.

The Board accepts the proposed operating expense forecast for the test year period 2003-2004, with the exception of executive compensation which is dealt with separately below.

The Board will no longer require NP to file an annual Advertising and Marketing Report.

Executive Compensation

The Consumer Advocate has taken issue with the level of executive compensation in this proceeding and has asked the Board to reduce the level of compensation recovered in rates.

In P.U. 36(1998-99) the Board reviewed in detail NP's overall methodology for setting executive and management compensation. During the 1998 proceeding NP submitted that its executive compensation plan was appropriate on the grounds that [Order No. P.U. 36(1998-99), pg. 36]:

i) the process of determining compensation used by the company was reasonable, involving the Board of Directors (absent of the executives involved), Hay Management Group and a Human Resources Committee with independent parties;
ii) the targets used are reasonable and represent an all Canadian industrial reference community; and
iii) the implementation of the executive and management compensation plan below target was reasonable and conservative.

NP also argued at the 1998 hearing that, with respect to Short Term Incentives (STIs), the 1999 test year figures are based on bonuses at 100% of target, as compared with the awarding of 130% of target in 1997. Bonuses in excess of 100% of target are the responsibility of the shareholder. During the 1998 proceeding the Consumer Advocate took issue with the level of executive compensation and the magnitude of increases over a two-year period. Other issues raised by the Consumer Advocate in 1998 concerned the use of the all Canadian Industrial reference group and NP's assertion that it needed to use this reference community in order to be able to attract, motivate and retain executives.

In Order No. P.U. 36(1998-99) (pg. 41) the Board "*accepted the level of executive and management compensation as reasonable, in the absence of any evidence to the contrary*".

In this Application NP has not proposed any changes to the methodology for setting executive compensation. The following table compares the average base salaries, STI payouts and other compensation for the period 1999-2002, and for the forecast period 2003-2004.

Executive Compensation 1999-2004F (Based on CA-664)						
Year	**Total Base Salary [1]**	**% Change**	**Total Short Term Incentive[2]**	**% Change**	**Total Salary + STI**	**% Change**
1999	667,887		200,000		867,887	
2000	721,922	8.09%	268,558	34.28%	990,480	14.1
2001	818,000	13.31%	430,000	60.11%	1,248,000	28.0
2002	875,000	6.99%	487,500	13.37%	1,362,500	9.2
2003F	903,100	3.21%	257,775	-47.12%	1,160,875	(14.8)
2004F	930,193	3.00%	265,509	3.00%	1,195,702	3.0

[1] Certain figures have been omitted from the table for consistency and comparison purposes. Corporate Counsel & Secretary was removed from Management to Executive in 2001, and the Vice President, Engineering & Energy Supply retired in 2001 without being replaced.

[2] STI forecast for 1999 test year (during 1998 general rate application proceeding) at 100% payout for revenue requirement calculation. Grant Thornton's report filed at the 1998 proceeding (pg. 5) indicates 100% payout of STI was $164,400. This table shows actual STI payouts, over and above the 100% payout level.

The Consumer Advocate argues that, since the Board approved NP's executive compensation in 1998, the level of compensation has risen dramatically. The Consumer Advocate also took issue with the submission of NP that it is necessary to compensate executives on a national scale to be able to attract and retain executives, suggesting that NP could provide but one example of an executive recruited on a national scale. It was argued by the Consumer Advocate that the evidence is that NP's policy is to promote from within NP and by way of transfer from within the Fortis Group of Companies, with three members of the Executive Team being transferred to Fortis since 1998. The Consumer Advocate favours the approach taken by the Nova Scotia Utility and Review Board (NSUARB) in their recent decision concerning executive compensation at Nova Scotia Power Inc. (NSUARB-NSPI-P-875, October 23, 2002), stating that the circumstances are similar. (Final Submission, Consumer Advocate, pg. 61)

The Governance and Human Resources Committee of NP's Board of Directors is responsible for providing advice and recommendations to the Board of Directors regarding bonuses and incentives as well as total annual compensation to NP's executives. Final approval of overall compensation and bonuses is made by the Board of Directors. Mr. Bruce Chafe, Chair of the Board of NP and Chair of the Governance and Human Resources Committee testified on the issue of executive compensation. In responding to questioning from the Consumer Advocate on the level of compensation paid to NP's executive Mr. Chafe provided the following comments: (Transcript, April 4, 2003, pg. 6-7)

Q. So could you comment, please, Mr. Chafe, on the level of compensation paid to Newfoundland Power's executive?
A. I firmly believe that the compensation paid to the executives of Newfoundland Power is fair and reasonable.
Q. And are there basic goals within which—that you aim for in establishing the level of executive compensation?

A. There are two primary goals. One is to attract and retain competent, skilled professional executives, and to do this, we have to set their base compensation on a median of industrial companies in Canada. We believe this is fair. Newfoundland Power is a large—I like to think of it as an industrial company, complex company, and I believe to base it on a median of industrial companies in Canada is reasonable, given that the market for these executives, this talent that we have to employ, is of a national scale.

The second, having set the base salaries, the second plank, and I believe these are the fundamentals to properly rewarding any executive group, the second plank is to provide an incentive. It's one thing to pay a base salary. Another is to provide a financial incentive primarily to ensure their performance. In Newfoundland Power's case, we have a balanced set of operating objectives which we set, as I mentioned earlier, in the meetings, the targets and goals to be achieved and these are pretty mathematical, as well as practical, and these targets include reliability, safety, controlling operating costs, and earnings.

Grant Thornton reviewed NP's approach and process with respect to setting executive compensation and compared it to the approach and process used in 1998, concluding (Grant Thornton Report-NP 2003 GRA, pg. 39):

"Essentially the approach used today is the same as in 1998. Specifically, the overall design and components of the plan have not changed and the policy of setting compensation by reference to the median of the Canadian industrial practice is consistent with 1998."

The 2001 Hay Report (CA-251) reviewed the job evaluation ranking of executives, the competitive position of the individual elements of compensation, and the existing compensation policy. The analysis in the 2001 Hay Report compares compensation practice at NP to that of the median of Canadian Industrials, and outlines the recommendations with respect to compensation at NP. The most significant recommendation affecting executive compensation concerned the design of the STI program and non-cash benefits.

In the Board's view the information before it does not support the Consumer Advocate's contention that Executive Salaries have risen dramatically since 1998. While overall levels of compensation have increased, annual base salary increases have ranged from approximately 3%-8% once the salaries are normalized to adjust for retirements and hirings. These base salary increases are not, in the opinion of the Board, unreasonable. Most of the increase in overall compensation has been in the areas of STI payouts. However, the Board notes that STI payouts in excess of 100% of target, as approved by the Board in 1998, were borne by the shareholder, Fortis, since these amounts were not included in the 1999 test year revenue requirement. The forecast STI payouts for 2003 and 2004 in revenue requirement are based on 100% payout and are significantly lower than the payouts for 2000 and 2001.

In cross-examination of Mr. Hughes, Board Hearing Counsel raised the issue of STI payouts in excess of 100% of target in a year where NP had declared portion of the STI payout above 100% would decrease the amount of excess earnings that would otherwise have been declared by NP.

Q. So, in a situation like that can I ask you what your view would be on that 150,000 figure that we're using, do you see that as a figure that should more properly be taken from the amount that would otherwise go to the shareholder as opposed to the amount that would otherwise go to the ratepayer?

A. I think it's one of those issues you can argue many ways. This is just my opinion, and I think there are other valid opinions. I think where the Company has produced on the tax operating costs and the Aliant poles excess earnings of $6.6 million for the benefit of consumers, the fact that an extra 100,000 retained by the Company I don't think is a huge issue. I understand the theory and I think you're right, Mr. Kennedy. You know, I mean, it's obviously true. But, I suppose I can't help but think that surely that's good for customers that the costs are coming down and so on. But, it's one of those issues, unlike some others, where I think it's legitimate to have different thoughts on it. You know, that happens to be my thought, but I-

Q. It's not a policy carved in stone, if you may?

A. I think different people would take different positions on something such as that. You know, you asked me what my opinion, and I view, well, it was $6.6 million rebate against 100,150, but somebody could argue it the other way.

(Transcript, March 6, 2003, pg. 14/6-25; pg. 15/1-12)

This issue was also addressed by the Consumer Advocate in final written submission (pgs. 61-62) stating that, if the STI payouts additional to the forecast had not been paid out, the same would have gone to excess earnings. The Consumer Advocate argues that NP's shareholder should be responsible for one-half of the compensation paid to NP's executives.

NP's revenue requirement for the test year includes an amount for STI payouts at 100% of target, and payouts in excess of this amount are borne by the shareholder, Fortis. The Board agrees that customers do benefit in the long-term when efficiencies are achieved and agrees that the use of STI payouts is an appropriate means of encouraging such efficiencies. However, the Board recognizes that such efficiencies also benefit the shareholder and concludes that any STI payouts in excess of 100% of target should be paid by the shareholder. This applies to both executive and management STI payouts.

The Board will direct that any STI payouts in excess of 100% of target payouts will be the responsibility of the shareholder, Fortis, and will be charged to non-regulated operations.

The Board agrees with the Consumer Advocate's submission that *"…the Board has within its purview the ability to set an amount for executive compensation and ratepayers would not be responsible over and above that amount."* (Final Submission, Consumer Advocate, pg. 61) However, the Board in this case has not been provided with any evidence other than the assertion by the Consumer Advocate that compensation levels are too high. While the levels of individual compensation may be considered high by some measures, the Board does not have any information on the record which would enable it to evaluate other appropriate alternative comparators for NP's executive compensation.

The Board will accept the level of executive compensation as reasonable for the purposes of determining test year period costs.

The Board accepts the level of executive compensation as part of NP's revenue requirement for the test year period 2003-2004.

iii) Depreciation Expense

The depreciation expense forecast for 2003 and 2004 reflects the depreciation rates recommended in the 2002 Depreciation Study and a true-up of $5,793,000 per year in each of 2003, 2004 and 2005.

The proposed depreciation expense for 2003 and 2004 is summarized below [Pre-filed Evidence, B. V. Perry, (1st Revision), pg. 60]:

Schedule of Depreciation: 2003-2004 (000s)		
	2003	**2004**
Depreciation Expense – Current Year	37,369	38,797
Adjustment for Proposed Depreciation Rates	(2,342)	(2,425)
Adjustment for True-up	(5,793)	(5,793)
Proposed Depreciation Expense	**29,234**	**30,589**

The Board has approved the updated 2002 Depreciation Study and revised depreciation rates as well as the true-up adjustment on pgs. 81-82 of this Decision. No objections or issues were raised with respect to the level of depreciation expense.

The Board accepts the depreciation expense for the test year period 2003–2004, as proposed by NP.

iv) Income Taxes

NP's forecast income tax expense for the test year period incorporates the tax impacts of the proposed increase in customer rates and the accounting changes described elsewhere in this Decision. No issues were raised with respect to this forecast expense.

The Board accepts the forecast income tax expense for the test year period 2003-2004, as proposed by NP, subject to any adjustments arising from this Decision.

v) Return on Rate Base

NP's forecast of return on rate base was calculated based on a forecast return on regulated common equity of 10.75% as proposed in its Application. As a result of the findings of the Board in this Decision, NP will be directed to recalculate the return on rate base. The revised amount will be incorporated into NP's revised filing of revenue requirement arising from this Decision.

3. Deductions from Revenue Requirement

NP's revenue required from consumer electrical rates is reduced by other revenue received by NP and also by deducting expenses incurred by NP in non-regulated activities. In this Application NP has also proposed applying 2001 excess revenue of $944,000 to offset revenue requirement for the 2003 and 2004 test years.

These deductions are dealt with separately below

i) Other Revenue

NP has forecast other revenue of $7,787,000 in 2003 and $8,593,000 in 2004. This revenue is primarily derived from pole attachment revenue ($6,430,000 in 2003 and $7,333,000 in 2004) with other amounts received from customer jobbing, wheeling charges, fees and miscellaneous sources. [Pre-filed Evidence, B. V. Perry, (1st Revision) pg. 7]

The Board accepts the deduction from revenue requirement of other revenue for the test year period 2003-2004, as proposed by NP.

ii) Adjustment for 2001 Excess Revenue

The Board dealt with NP's proposal for the disposition of the Excess Revenue Account on pgs. 84-85 of this Decision.

Since the Board will require that the 2001 Excess Revenue be rebated to customers, NP's revenue requirement will not be reduced by this amount, as proposed by NP.

iii) Non-Regulated Expenses

Non-regulated expenses are those expenses that are not recoverable through rates under Section 80(2) of the *Act*. NP has estimated non-regulated expenses, net of tax, of $725,000 in each of 2003 and 2004.

Grant Thornton reviewed the non-regulated expenses recorded by NP for the period ended September 30, 2002 and the forecast non-regulated expenses for 2002, 2003 and 2004. Grant Thornton's conclusion was that the non-regulated expense forecast appeared reasonable and is in accordance with Board Orders, including P.U. 7(1996-97).

The Board accepts the deductions from revenue requirement of non-regulated expenses for the test year period 2003-2004, as proposed by NP.

4. Summary of Allowed Revenue Requirement

NP will be required to calculate and file a revised revenue requirement for 2003 and 2004 based on its proposals in this Application, and incorporating the changes set out in this Decision relating to the allowed rate of return on rate base and the adjustment for 2001 Excess Revenue.

The Board will accept, subject to review of reasonableness and prudence, certain other secondary or incidental changes in revenue requirement which arise as a result of this Decision.

X. COST OF SERVICE

1. Background

NP's Cost of Service methodology was last reviewed by the Board at the company's 1996 general rate proceeding. At that time NP proposed changes to its Cost of Service methodology to reflect where appropriate recommendations arising from the 1992 generic Cost of Service Study hearing. In Order No. P.U. 7(1996-97) the Board approved NP's proposed changes on a temporary basis and ordered a detailed review of NP's Cost of Service methodology at its next rate hearing. The changes reflected the 1992 generic Cost of Service methodology, which was also adopted by NLH as part of its last general rate hearing.

Specific changes proposed by NP and temporarily approved by the Board in Order No. P.U. 7(1996-97) are as follows [Pre-filed Evidence, L. Henderson, (1st Revision), pg. 6]:

- Classification of NP's hydraulic plant using system load factor on energy rather than 100 % demand;
- Allocation of NP's generating plant (hydraulic and thermal) using a single coincident peak allocation ("*1 CP"*) rather than non-coincident peak allocation ("*NCP*");
- Allocation of NP's transmission plant using 1 CP rather than NCP;
- Allocation of purchased power transmission demand costs using 1 CP rather than NCP;
- Allocation of purchased power generation demand costs using 1 CP rather than NCP; and
- Allocation of NP's funding of NLH's rural deficit based on allocated class cost and removal of the rural deficit from the calculation of revenue to cost ratios. Prior to 1996 the rural deficit was included in the purchased power expense and classified based on the demand energy split for purchased power expense.

2. NP's Proposed Cost of Service Methodology

For the most part NP has incorporated into its Cost of Service methodology the Board's recommendations for NLH's Cost of Service study as approved in Order No. P.U. 7 (2001-2002) with the exception of the following (Exhibit LCH-1, pg. 4):

- NP uses a single NCP allocator for distribution costs related to demand while NLH uses the ICP allocator;
- NP uses a minimum system analysis (also called minimum size method) to classify distribution conductor, pole and fitting costs as either customer related or demand related while NLH uses the zero intercept method; and
- NP does not assign any of its transmission costs to the generation function and consequently none are allocated to energy.

3. Mediation Report

As discussed on pgs. 4-5 of this Decision the parties to this proceeding agreed to put the Cost of Service and Rate Design issues to a mediation process. As a result a consent Mediation Report was filed and accepted by the Board as part of the proceeding, with the Board agreeing to incorporate into its Decision the recommendations of the parties as set out in the report.

The parties agreed in the Mediation Report that the Cost of Service proposals temporarily approved by the Board in Order No. P.U. 7(1996-97) should be approved in this Decision.

In addition the Mediation Report recommended the Board approve two additional changes to NP's Cost of Service methodology:

- General expenses (i.e. General System Costs and Administration and General Costs) should be functionalized and classified based on the assumption that a portion of these costs is related to net utility plant (capital labour expense as a percentage of capital labour expense plus operating labour expense), rather than assuming (as previously) that all of these costs relate to operating and maintenance (O&M) expense; and
- The Cost of Service study should use normalized revenue and normalized purchased power expense rather than actual revenue and purchased power expense, unadjusted for normalization, as previously.

It was also recommended that the Board approve NP's use of an NCP allocator for distribution demand costs even though this differs from the 1 CP allocator that NLH was directed to use for distribution demand costs in Order No. P.U. 7(2002-2003).

The Board has reviewed the Mediation Report and the evidence filed relating to Cost of Service issues. The Board accepts the recommendations of the parties as set out in the Mediation Report and will approve the recommendations as presented.

4. Future Load Research

The evidence filed by NP's Cost of Service expert witness Mr. L. Brockman indicated that NP's current load research data is nearing the end of its useful life as a predictor of class demand. This information is important in ensuring that the allocation of demand costs among customer groups is fair. To ensure the best available information on customer class demand is used updated load research data is necessary. NP is proposing to implement a new load research program including representative samples from each customer class. The load research study period is planned to begin in the 2003-2004 winter season and has a forecast capital cost of $425,000 for the metering, meter reading equipment and computer software. NP has requested approval of this additional amount as part of its capital expenditures for 2003.

The parties agreed in the Mediation Report that this expenditure should be approved.

The Board will approve additional 2003 capital expenditures of $425,000 for a load research program, as proposed by NP.

XI. RATES, RULES AND REGULATIONS

1. Mediation Report

In the Mediation Report the parties recommended the following with respect to rate design:

- The Board should approve tail block rate increases above the average class increase for Rates 2.2, 2.3 and 2.4 so as to better reflect short-run marginal energy costs in these tail block rates;
- The Board should approve the elimination of minimum monthly ("ratcheted") demand charges, linked to the customer's maximum demand during the previous twelve months, in General Service Rates 2.2, 2.3, and 2.4.
- The Board should retain the Curtailable Service Option Credit of $29/kva in Rates 2.3 and 2.4 and require NP to inform customers of the possibility of significant future changes in this credit.[1]
- The Board should approve NP's proposed merger of street light and area lighting rates for the 400W MV fixtures with the 250W HPS fixtures that replace them. The Board should also approve NP's proposed removal from the Schedule of Rates, Rules and Regulations, the charges for the 1,000W MV fixture, the 700W MV fixture and the 150W HPS post top fixture, since these no longer exist on NP's system.
- To the extent possible, there should be no adverse customer rate impacts. Any overall revenue change should be distributed equally to each class of customers. With the exception of any change in basic customer charges, no customer should have a rate change that produces an annual cost change that is more than twice the system average (unless the dollar impact is minimal).[2]
- The Board should approve a change to Regulation 9(o) to reduce the application fee for a customer name change from $14.00 to $8.00 (the current new service fee).
- The Board should approve the removal of clause 9(n) to eliminate charges for the preparation of account statements for billing information prior to the most recent twelve months.
- The Board should approve a change to Regulation 9(f) and a proposed new clause 12(g) permitting charging the reconnect fee to new customers in apartments where a reconnection is required subsequent to a request by a landlord to disconnect an apartment. Such customers will not be required to pay the new service application fee.

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[1] It was noted in the Mediation Report that whereas NP states the $29 credit "is reasonable" the CA's position is that until there are cost-reflective wholesale power purchase rates (from Newfoundland Hydro), benefit to NP from the Curtailable Service Option will be hidden, and there is now little evidence to suggest changing the current option. The implication is that while all parties agree that the Curtailable Service Option Credit should now be retained as it is, a change may be appropriate if Hydro's wholesale rates change.

[2] It was noted in the Mediation Report that possible future rate changes, such as those that may be justified by the results of future load research, may warrant a redistribution of revenue responsibility between rate classes and/or annual cost changes for some customers that differ significantly from the system average.

- The current basic monthly customer charges for domestic (residential) service and small general service rate 2.1 should be reduced by $1.00. The revenue loss associated with this change should be made up by adjusting the energy component of these same rates so that the change does not impact customers in other rate classes.

As part of this proposal NP also agreed that: (1) it will not propose a basic customer charge increase as a result of any wholesale rate increase in NLH's 2003 general rate proceeding; and (2) in its next general rate application, NP will cap the customer charge recovery of distribution costs allocated to customers at 50% of these allocated distribution costs for rate classes, with the remainder to be recovered through energy charges. 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.

It was also agreed by the parties to recommend that the Board proceed, as planned, to consider implementation of improved cost-reflective wholesale power rates to be charged to NP by NLH. To facilitate that process, the Board should schedule (and provide such notice as may be required) a one-day consultation to take place within 30 days after NLH's general rate filing, wherein NLH would discuss and provide information to stakeholders on its proposed wholesale power rate design.

As well the parties recommended that the Board direct NP, in consultation with the Consumer Advocate and Board Staff, to propose a *"peer group"* of utilities and performance measures upon which to evaluate NP's performance. Upon Board approval of the peer group and performance measures, NP will collect and report annually statistical information relative to the peer group performance. NP should be entitled to recover its reasonable documented costs of this effort.

The Board has reviewed the Mediation Report and the evidence filed relating to Rate Design issues. With the exception of the issue relating to meter reading, which was not agreed to by the parties, the Board accepts the recommendations of the parties as set out in the Mediation Report and will approve the recommendations as presented.

Since the conclusion of the hearing of this Application, NLH has filed its general rate application for 2004. The Board will direct that the scheduling of the consultation recommended in the Mediation Report on NLH's wholesale power rate design be considered at the pre-hearing conference for NLH's general rate application.

The Board will direct NP to propose to the Board for approval of a *"peer group"* of utilities and performance measures upon which to evaluate NP's performance in accordance with the terms of the Mediation Report.

The Board once again expresses its appreciation for the efforts of the parties in settling these issues through the mediation process.

2. Outstanding Issues Relating to Rates, Rules & Regulations

i) Meter Reading

During mediation the issue of meter reading as provided for in NP's Rules and Regulations was not agreed upon by the parties. The Consumer Advocate recommended in the Mediation Report that the wording of the first sentence of *"Rules and Regulations 8. Meter Reading"* should be revised to read:

> *"With the exception of circumstances beyond its reasonable control, the company shall read meters monthly."*

NP recommended retaining the present language which states:

> *"Where reasonably possible the Company shall read meters monthly provided that the Company may, at its discretion, read meters at some other interval and estimate the reading for the intervening months."*

The parties agreed that the resolution of this issue does not require the calling of expert cost of service or rate design witnesses, and that the Board panel is able to resolve the issue based on arguments that the parties will make in their briefs and on hearing examination of the parties' policy and revenue requirement witnesses.

The Consumer Advocate's position as set out in the Mediation Report was that customers who receive estimated bills often think that the estimates are high and that they would prefer an actual meter reading rather than an estimated bill. The Consumer Advocate also argued during the hearing that, since NP is paid as part of the basic customer charge to read meters, estimates should only be allowed in exigent circumstances. The Consumer Advocate also submits that the practice of estimating meters during the summer months should be stopped.

NP believes that its estimates are reasonably accurate, that there are few customer complaints and that the estimation process during summer vacation months saves costs (approximately $40,000) by reducing the need for temporary employees. NP submitted that the summer estimating program is a management issue, and that the program is part of an overall approach to manage the cost of meter reading. Savings from the summer estimating program ranged from $20,000 to $45,000 for the years 2000 to 2002, compared to total meter reading costs of $2,000,000 per year. Based on these savings NP plans to continue with its summer meter reading program. NP's position is that no change in Regulation 8(a) is warranted. (Written Submissions, NP, Section F, pgs. 3-4)

The Board has reviewed the submissions of the parties on this issue and notes that there appears to be a number of separate issues raised, namely meter reading frequency, the recovery of the costs of meter reading and estimation of meters.

The issue of monthly vs bi-monthly meter reading was addressed by the Board at NP's 1996 general rate hearing after which the Board accepted NP's proposal to return to monthly meter reading. The issue of the summer estimating program is not, in the Board's view, related to monthly meter reading but is rather a management issue aimed at efficiencies and cost savings. Under the existing regulations NP has the discretion to implement such a program and did not seek the Board's approval at the time. The Board notes the savings to ratepayers of the estimating program. The Board has monitored this program since it was put in place by NP in 2000 and observes that it does not appear to have had any adverse impact on customers. The Board will not order NP to end this program at this time and incur additional costs to be recovered from ratepayers.

The costs of meter reading are recovered by NP in the Basic Customer Charge (BCC). The BCC includes those customer related costs that occur because a customer is connected to the system, regardless of whether energy is used or demand is incurred. These costs usually include the cost of the meter, the cost of the service wire, and the costs associated with billing customers, including meter reading costs, collection costs, billing system costs and customer service costs. NP's expert witness on Cost of Service confirmed that NP's BCC for residential and small general service classes recovers 100% of the cost of metering, billing, customer information and service wire costs, and 60% of the customer related distribution system cost. (Pre-filed Evidence, L. Brockman, pg. 10)

Even though the BCC recovers those costs associated with meter reading, it is not correct to say that NP is being paid to read every customer's meter. The BCC recovers NP's total customer related costs by spreading the total of those costs to all customers connected to the system, regardless of where they live or how much each customer contributes to the BCC on an individual basis. The BCC represents in effect the average customer cost and does not reflect the actual cost of the specific components of the cost, such as the cost of reading that customer's meter. In the Board's view the issue of recovery of meter reading costs is not an issue in this hearing requiring a determination by the Board. NP is entitled to recover its total cost of providing service and, if the costs are not recovered in the BCC, the costs will be recovered in rates.

It is the role of the Board to investigate, mediate and try and resolve complaints from customers experiencing problems with the utilities. The Board's regulatory staff tracks complaints and their resolution and through this process is able to identify issues which may require intervention with the utility by either the Board or its staff. For example it was as a result of this complaint process that the Board initiated a comprehensive review in 1996 of the CIAC Policy, culminating in a public hearing in the fall of 1997.

Several specific examples were raised during the hearing, both by the Consumer Advocate and by individual presenters, regarding meter reading practices of NP. As well since the commencement of this hearing Board staff have received a number of complaints regarding meter reading and estimating of meters such that a review of this issue is viewed by the Board as warranted at this time.

The Board will not direct any changes to the wording of Rules & Regulations 8-Meter Reading at this time. The Board will undertake a review of NP's meter reading program with a focus on the estimating methodology and process. This review will also include an assessment of existing regulatory and utility practice in other Canadian jurisdictions.

ii) Demand Charges for Recreational Facilities

Mr. Gary Milley of the Newfoundland & Labrador Parks/Recreation Association raised the issue of demand charges for major recreational facilities during his presentation to the Board in St. John's. Mr. Milley requested the Board to consider either reducing or eliminating the demand rate charged community facilities such as stadiums and swimming pools. If this couldn't be done Mr. Milley requested that some type of rebate or benefit program be put in place for community facilities. (Transcript, April 3, 2003, pg. 81)

NP's position on this issue is that elimination or reduction of demand charges to these customers for essentially social welfare considerations is not consistent with the objectives of good rate making. NP points out that a similar discount on demand charges provided to churches and schools was eliminated during the 1980s. [P.U. 47(1982), P.U. 51(1982)] NP submits that demand charges that apply to major recreational facilities should be maintained at the same level as those for other general service customers served under the same respective rate class. (Written Submissions, NP, Section F, pgs. 6-7)

No other submissions were made by other parties on this issue.

The Board has been presented with similar requests in previous hearings, which essentially petition the Board to consider the *"ability to pay"* of the consumer. The Board has outlined its position on this issue in reference to its statutory powers and responsibilities on pg. 17 of this Decision. While the Board acknowledges the challenges these major recreational facilities face with respect to operating costs in general, and costs for electricity consumption specifically, the Board agrees with NP that demand charges should be maintained at the same level as those for other general service customers. This is consistent with cost based ratemaking and is fair and equitable to all customers in that class. To do otherwise would involve a subsidy to one group of customers at the expense of another. The Board notes that the approval of NP's proposal to discontinue demand related minimum monthly charges will partially address some of the concerns raised by Mr. Milley.

The Board will not make any adjustments to the application of demand charges within the General Service Rates.

iii) Availability of the Domestic Rate

Mr. Owen Crossan of Regency Management Ltd. and Mr. Charlie Oliver of Martek Morgan-Finch requested the Board amend NP's Schedule of Rates, Rules and Regulations so that the rates for the house meters of apartment buildings be classified as a residential rate, instead of a commercial rate. Their position is that the house meter in an apartment building is used for a non-commercial, exclusively domestic use such as washers and dryers and lights in hallways and stairways. Mr. Crossan submitted that the Provincial and Federal Government have, through taxation policies, agreed that apartment buildings are solely for residential use and should be classified as such. He cited as examples the fact that the Provincial Government does not require HST to be charged for the use of the washers and dryers by the tenants and the fact that the Federal Government does not require payment of HST on a lease of one month or more.

NP submits that the common areas of apartment buildings and condominiums provide a service to all tenants of the facility and do not meet the definition of a Domestic Unit in the Rules and Regulations. The *"Customer"* in the case of the common area is the management of the apartment building or condominium, and is not the same *"Customer"* as referred to in the Availability Clause for the Domestic Rate 1.1. NP argues that the management of the apartment complex or condominium is engaged in a commercial enterprise and the service provided by the appropriate General Service Rate. (Written Submissions, NP, Section F, pg. 10)

NP also notes in written submission (Section F, pg. 10) that this issue has been before the Board in previous hearings in 1987, 1989 and 1991. At these hearings the Newfoundland and Labrador Pensioners and Senior Citizens Federation requested that Domestic Rate be used for their clubrooms rather than the General Service Rate. In Order No. P.U. 6(1991) the Board confirmed NP's definition of a Domestic Unit and found that these clubrooms do not meet that definition. [P.U. 6 (1991), pg. 80-81]

NP's Rules and Regulations define a *"Domestic Unit"* as follows:

> *"Domestic Unit means a house, apartment or similar residential unit which is normally occupied by one family, or by a family and no more than four other persons who are not members of that family, or which is normally occupied by no more than six unrelated persons."*

If a customer does not meet this definition of a domestic unit the rate charged will be the applicable General Service Rate, depending on demand. Common areas of apartment buildings or condominiums do not meet the definition of the Domestic Rate class in NP's rate structure. In the Board's view making the domestic rate available to common areas of apartment buildings and condominiums would not be fair to other customers in substantially similar circumstances who are also charged a commercial rate.

The Board agrees with NP's submission that the management of the apartment complexes and condominiums are engaged in commercial activity. The argument against this position appears to be based on the fact that the end users of the electrical service are the same tenants who live in the buildings and who meet the definition of *"Domestic Unit"*. However, the *"Customer*" in the case of the common areas of the building for the purpose of provision of electrical service by NP is the building management and not the tenant. This service is properly charged under the commercial rate structure, and presumably the costs are incorporated into the rental rates of the tenants.

The Board will not order the Domestic Rate be made available to house meters of apartment buildings.

iv) Requirement for Security Deposit

In presentations to the Board during public participation day in Corner Brook, Mr. Mark Baldwin and Mr. Peter Blake raised the issue of the appropriateness of NP's policy regarding payment of security deposits and its effect on small business. Mr. Blake is a small business owner in Corner Brook who testified about the impact the requirement to pay a security deposit required has on cash flow and start up costs for a small business in its first year of operation. Mr. Blake also questioned the interest rate of two percent less than prime which is paid by NP on deposits stating that in his view NP is making a profit off his deposit. (Transcript, April 11, 2003, pgs. 74-79)

In written submission (Section F, pgs. 11-14) NP argued that the requirement of a security deposit helps to minimize costs resulting from the outstanding bills left by new businesses which fail. If the security deposit were not in place other customers would have to pay those costs. As electrical service is provided in advance of payment by customers, the amount of deposit, equivalent to two months usage, is viewed by NP as justified.

NP further argued that the existing annual expense of $700,000 for uncollectable bills (net of application of security deposits) would increase to approximately $1,100,000 annually if the Customer Deposit Policy was not in place. As to the interest paid on deposits, NP's position is that the rate paid on cash security deposits is approximately equal to the rate the customers would earn on a 2-year GIC and similar to the rate NP pays on short-term borrowings, and hence is reasonable.

Regulation 4 (a) of the Rules and Regulations states as follows:

> *"4. Security for Payment*
> *(a) An applicant or a customer shall give such reasonable security for the payment of charges as may be required by the Company pursuant to its Customer Deposit Policy as approved by the Board, from time to time."*

The Board approved the existing Customer Deposit Policy in March 1988. This policy sets out the conditions under which reasonable security for payment shall be required and also sets out the form of the security as either cash deposit, bank letter of credit, payment bond, letter of guarantee or any other form of security acceptable to NP.

In addressing this issue the Board acknowledges that the payment of a cash security equivalent to the average cost of two months service may create a financial burden for certain new businesses. However, the Board also recognizes a fairness principle in that, if these new businesses do fail other customers will have to pay for the costs incurred to provide electrical service for which NP will not recover. The security deposit has been used to offset these potentially unrecoverable costs in the past. The Board notes the amount of $400,000, which is the difference in uncollectable bills net of application of the security deposit, as a significant cost to be borne by other customers.

In the Board's view this would not be fair to other customers on the system, especially those who have already paid their full cost towards their electrical service. The existing policy is seen by the Board as reasonable and in the best interests of all customers. The Board notes that there are several options as to the form of security a new business customer may elect to provide and expects that these options are made known by NP and available to customers.

The Board is not persuaded that changes to the Customer Deposit Policy or to the Rules and Regulations respecting security deposits would be fair to other customers. The Board will not order a change in the present policy covering the rate of interest paid to customers on cash security deposits.

v) Requirement for Inspection of Service Prior to Reconnection

In his presentation to the Board Mr. Crossan also requested that the Board eliminate the requirement for inspections prior to the reconnection of service where the unit is vacant for any period of time and there has been no electrical work or repairs carried out. According to NP, this requirement is based on written direction from the Province's Chief Electrical Inspector that, where a service has been disconnected for more than 90 days, an electrical inspection is required prior to the reconnection of service. Mr. Crossan stated that it was his understanding this requirement is as a result of an existing rule of the Board.

The Board does not have any such rule in place relating to inspections prior to reconnections. This requirement is put in place for NP by the Province's Chief Electrical Inspector. NP states that it must abide by the requirements of the Chief Electrical Inspector unless informed otherwise and that it has no discretion with respect to this issue. The Board agrees with NP.

The requirement for inspection of service prior to reconnection is primarily a safety issue and the Board will not intervene.

vi) Rate Change Implementation

In order to finalize rates to be implemented as a result of this Application, NP will be directed to re-file, along with its revised revenue requirement and revised calculations of rate base and return on rate base, its Schedule of Rates, Tolls and Charges to be effective for billings on or after August 1, 2003 incorporating the decisions of the Board. The rates shall be calculated on the same basis as in the Application and shall be designed to remain in effect through 2004.

NP will also be directed to file a proposal as to the finalization of interim rates as set by Order No. P.U. 35(2002-2003) and the disposition of any variance between revenue generated based on these interim rates and the revised 2003 test year revenue requirement. The proposal should include a plan for the rebate of this amount to customers.

The Board will review NP's revised filing to ensure its decisions are appropriately incorporated and then issue a final Order, approving or modifying, as it deems appropriate, NP's rate base, NP's return on rate base and the revised rates for NP's customers as of August 1, 2003.

XII. OTHER ISSUES

1. Conservation/Demand Side Management

The issue of conservation and demand side management was raised in this proceeding by the Consumer Advocate. In final submission (pg. 74) the Consumer Advocate stated that "*NP's efforts toward conservation are virtually non-existent.*" The effectiveness of NP's activities in demand side management and energy efficiency programs was also questioned by the Consumer Advocate. He cited the evidence provided by Ms. Sarah Peckford and Mr. Terry McNeil, both of the Conservation Corps, who made a presentation to the Board during the public participation day in St. John's. Due to a lack of funding the Conservation Corps has had to lay off staff and the partnership negotiated between the Corps and NP as of December 2002 is effectively at an end. This means that Newfoundland and Labrador is the only province in Canada in which an Energuide Assessment Program is not available. The Consumer Advocate argues that

> *"This lack of a conservation agent and an Ener-Guide Assessment comes at a time during which consumers owe $100 million to pay the cost of Bunker C fuel burned at the Holyrood Generating Station, and it comes at a time during which consumers are using electricity more, not less. The average consumption in Newfoundland has risen.".*
> (Consumer Advocate, Final Submission, pgs. 75-76)

The Consumer Advocate requests that the Board provide policy and give specific and meaningful direction to the utilities on conservation issues.

The other parties to the hearing did not address this issue and NP did not provide its position in final submissions or oral argument. In addition to the presentation provided by the representatives from the Conservation Corps and their responses to questions, there were several information requests regarding conservation and DSM to which NP responded.

NP outlined its approach to demand side management and energy efficiency programs in its response to CA-239:

> *"The intent of DSM programs is to manage the demand side use of electrical energy in order to minimize electricity rates. During the last several years, Newfoundland Power has focused its DSM activities on programs that improve customer service and enhance the value customers receive from electricity. The Company has taken this approach because the size and isolated nature of the Newfoundland electrical system, and its current dynamics as reflected in load forecasts and generation cost projections, suggest that larger scale DSM activities are unlikely to have significant impact, either on load or on generation requirements. Unless circumstances warrant a change in direction, the Company will maintain the current focus of its DSM activities into the future.*
>
> *It is the intent of the Company that all customers benefit from the Company's DSM activities either directly as participants, indirectly as non-participants or through improved customer service. DSM initiatives will be assessed on an ongoing basis to ensure they meet the needs of the Company's customers."*

Since 1990 NP has been required to file annually with the Board a progress report of its DSM activities. These reports describe the benefits of NP's DSM activities, including results and associated costs. In the Board's view these reports have been informative and provides important information, especially with respect to customer based activities. The Board will continue to require these reports as ordered in Order No. P.U. 7(1996-97).

This issue was raised during the hearing of NLH's general rate application in 2001. In Order No. P.U. 7(2002-2003) the Board recognized and supported NLH's efforts in partnering with the Conservation Corps. The Board also stated that activities in this area should be implemented and monitored within the customer service group, as one of the main goals of such programs is improving customer access to conservation tools and energy saving initiatives, which is the case with NP. NP should consider expanding its customer satisfaction survey to obtain more specific information from customers with respect to conservation of energy and customer needs.

The Board supports NP's past efforts in partnering with the Conservation Corps to provide customer access to the Corps' services and encourages NP to continue to pursue similar partnerships and initiatives in the future. The Board was impressed with the presentation by the Corps on its programs and the potential benefits to homeowners in terms of energy conservation and resulting lower energy bills, and acknowledges the Corps' current funding challenges. NP was just one of the parties participating in supporting the Ener-Guide Program and the Board is not prepared to direct NP to support any particular conservation initiative on its own accord or to fund any specific group.

In the Board's view the issue of conservation and energy efficiency is one the Board can consider in the context of least cost electricity for consumers in the province. The relationship between rates and electricity consumption and the impact of DSM and energy efficiency programs is complex, especially when overlayed with the impact on the electrical system and generation planning. The differences in the structure and customer profile of each of the utilities also has to be considered. The Board acknowledges the reports on NP's DSM activities provide useful information. The Board finds it difficult, however, to provide specific and meaningful policy direction to the utilities on DSM and conservation issues in the absence of supporting evidence and related impacts on the system overall. This matter would be most appropriately addressed in the context of a generic proceeding involving both utilities and interested parties. The Board will consider the manner and timing of such a proceeding following the hearing of NLH's general rate application.

PART THREE. SUMMARY OF BOARD DECISIONS

1. SUBMISSION OF CONSUMER ADVOCATE ON EXCESS EARNINGS

1. The Board finds that it has no jurisdiction under the *Public Utilities Act* to require payment by NP into a reserve account or otherwise deprive NP of any amount which is within the allowed return on rate base as fixed and determined by the Board pursuant to Section 80(1) of the *Act*.

II. FORECASTING ISSUES

2. The Board will accept NP's customer and energy sales forecasts for the test year period 2003-2004.

III. RISK ASSESSMENT

3. The Board does not anticipate a change in the business risk of NP in the foreseeable future and concurs with the assessment of NP and the cost of capital experts that NP is of average business risk compared to other utilities.

4. The Board finds that capital market conditions, in particular affecting the equity market, have changed substantially since 1998. This volatility has contributed to an overall reduction in investor expectations in the equity market from historic levels. In addition, volatility has contributed to greater spreads being demanded by corporate bondholders and equity investors to account for added risk as compared to long-term government securities. The Board finds these trends will similarly influence NP but present no greater financial risk to NP than will be experienced by other comparable Canadian utilities.

5. The Board finds that based on its financial performance NP continues to sustain a sound credit rating which is providing appropriate and cost efficient access to the financial markets.

6. The Board concludes that in the interest of both the utility and its customers. NP should continue to be treated as a stand-alone utility. Therefore, the Board will require NP to take all appropriate steps necessary to preserve the financial integrity and independence of the utility. As a first step, NP will be required to file a report by June 30, 2004 addressing how it can ensure stand-alone status in respect of its corporate credit linkage by S & P to Fortis. This report should: 1) document discussions with the credit rating agencies and Fortis on this issue; 2) explain how other regulated Canadian utilities are facing similar challenges; 3) provide a list of possible mitigating actions; and 4) provide a plan of implementation of recommended actions.

7. Despite the change in circumstances since 1998, the Board finds that the overall investment risk of NP is average when compared to other Canadian utilities. This finding will be the basis on which the Board will consider a commensurate capital structure and ROE for the utility.

IV. FINANCIAL TARGETS AND OBJECTIVES

8. Having reviewed the evidence the Board is of the opinion that it is reasonable and prudent to maintain the capital structure deemed appropriate in Order No. P.U. 16(1998-99). The proportion of regulated common equity in the capital structure should not exceed 45%. Any regulated common equity in excess of 45% will only be entitled to a rate of return equal to the rate of return on preferred equity. For the purpose of determining the weighted average cost of capital, the Board accepts NP's proposed forecast average capital structure for the 2003 and 2004 test years.

9. The Board will continue to rely principally on the equity risk premium test and will determine a return on regulated common equity primarily with a view to establishing a risk-free rate based on long-term Government of Canada bond yields plus an appropriate risk premium.

10. The Board will utilize 5.60% as the forecast of the risk-free rate to be applied in the equity risk premium test for the test years 2003 and 2004.

11. The Board will make no adjustment to the equity risk premium test for financing costs.

12. The Board will incorporate a risk premium of 4.15% in the equity risk premium test in calculating the cost of common equity.

13. The Board will utilize a return on regulated common equity of 9.75% for the purposes of determining the WACC for both 2003 and 2004.

14. The Board finds an interest coverage in the order of 2.4x is acceptable given NP's level of risk and the Board's findings in this Decision with respect to NP's capital structure and return on regulated equity.

V. INTER-CORPORATE RELATIONSHIPS AND CHARGES

15. NP will be 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.

16. These principles may be amended by the Board from time to time. Given the implications of these principles on both NP and its affiliates, NP will be required to undertake a review and update of its operating practices and procedures relating to any and all inter-corporate transactions to ensure that the principles as set out above are reflected. The results of such a review shall be reported to the Board no later than March 31, 2004.

17. NP will be directed to prepare a report which should compare and quantify the benefits to NP and ratepayers of its administration of and participation in a centralized insurance program for the Fortis Group of Companies, rather than be insured on a stand-alone basis. This report should be filed with the Board no later than March 31, 2004.

18. NP will be required to modify its quarterly reports on inter-corporate charges to show separately associated labour and other staff and expense charges billed in relation to NP's insurance administration on behalf of Fortis and related companies.

19. As part of the review of operating practices and procedures relating to inter-corporate transactions NP will be required to investigate the utilization of market rates for executive and management time charges. In lieu of market rates, NP shall propose an appropriate markup on its cost-based rates as a proxy for market in the event that utilization of market rates is not practical.

20. NP will be required to apply billing and collection practices with respect to inter-corporate transactions which are consistent with those applied to unrelated parties. Billings to Fortis and related companies should also be undertaken within 30 days of the service and/or expenses being charged for recovery.

VI. AUTOMATIC ADJUSTMENT FORMULA

21. The Board will continue to use the existing methodology in the Automatic Adjustment Formula for calculating the risk-free rate. However, the risk-free rate will now be calculated based on the actual yields of the three most recent series of long-term Government of Canada bonds during the 10 trading days being monitored as reported in The Globe and Mail under the heading *"Ask Yields"*. The observed average of the daily ask yields for the last five trading days of October and the first five trading days of November for these three most recent issues will be used to forecast the risk-free rate for the upcoming year, in each year of operation of the Formula.

22. The Board has determined that a total risk premium of 415 basis points, or 4.15%, is reasonable. This is the value that will be used and adjusted on the same basis as was ordered in Order No. P.U. 36(1998-99) in the application of the Formula.

23. NP will be required to modify the schedule filed as part of its annual return that calculates the embedded cost of debt to identify specifically the causes of variations in the actual embedded cost of debt from the cost forecast for the test year period.

24. The Board will establish a mechanism tied to the observed rate of return on regulated common equity which may trigger an early review of the Formula and cost of capital. Where the actual rate of return on regulated equity in any intervening year exceeds the cost of equity determined by the Formula by more than 50 basis points, then NP will be required to file a report with the Board in its annual return setting out the circumstances and facts contributing to the difference.

25. The Board will approve the use of the Formula, as modified by this Decision, for a further three-year period. Customer rates will be set for 2003 and 2004 by this Decision and Order. The Formula will be used to set the rate of return on rate base, and hence customer rates, for 2005, 2006 and 2007.

26. The Board finds that the Asset Rate Base method should replace the Invested Capital approach currently used to calculate NP's rate base. The move to the Asset Rate Base method will begin in 2003 by incorporating deferred charges in rate base. The Board will direct NP to implement the following guidelines in switching to the Asset Rate Base method:

(i) Average deferred charges based on BVP-11 to be added to the average rate base for the 2003 and 2004 test years and all subsequent fiscal years.
(ii) Evidence relating to changes in deferred charges, in particular deferred pension costs, to be filed annually at the capital budget hearing.
(iii) NP will provide a reconciliation of average Rate Base to average Invested Capital annually at the capital budget hearing.
(iv) NP will review no later than its next general rate application, the appropriateness and approach to including the remaining reconciling items in the Rate Base. This review will address the issue of discontinuing the use of regulated common equity in favour of book equity.

VII. RATE BASE

27. NP will be required to file a revised calculation of rate base and return on rate base for test years 2003 and 2004 which reflects the decisions taken by the Board.

28. The Board will approve a range of 36 basis points for the rate of return on rate base for test years 2003 and 2004 and for use with the Formula, unless otherwise ordered by the Board.

VIII. ACCOUNTING TREATMENT AND POLICIES

29. The Board will accept NP's proposal to amortize the recovery of the $5,600,000 balance in the Hydro Production Equalization Reserve over a period of five years, beginning in 2003. NP will be required to review the balance in the Hydro Production Equalization Reserve as of December 31, 2005 and to apply to the Board for an Order as to the disposition of outstanding balances, positive or negative, as part of its next general rate application.

30. The Board will approve NP's proposal to adopt the market-related method of determining pension expense on a prospective basis, effective January 1, 2003.

31. The Board will approve the 2002 Depreciation Study as filed. The depreciation rates as recommended in the Depreciation Study will be approved for calculating depreciation expense for the test year period 2003 and 2004.

32. The Board will approve NP's proposal to amortize the depreciation reserve variance over the three-year period 2003-2005.

33. The Board will approve NP's proposal to continue with the cash basis for recognizing expenses for other employee future benefits. With its next general rate application, NP will be required to submit a report which addresses the use of the accrual method as an alternative to the existing accounting treatment for other employee future benefits.

34. The Board will approve NP's proposal to amortize over a three-year period, beginning in 2003, the estimated regulatory costs of $1,200,000.

35. The Board finds that the 2001 excess earnings of $944,000 should be rebated to customers. NP will be required to submit a proposal for this rebate as part of its filing of revised rates.

36. The Board will accept NP's proposal for adjusting 2003-2004 revenue requirement to recover the outstanding amount of the 1992-1993 excess earnings as required by Order No. P.U. 36(1998-99), subject to any adjustments arising from this Decision.

37. The Board will approve NP's request to defer dealing with the outstanding issues relating to the Revenue Recognition Study pending resolution of the dispute with Canada Customs and Revenue Agency (CCRA).

38. Since the Board has agreed to the deferral of the issues relating to the Revenue Recognition Study until the dispute between NP and CCRA is resolved, the Board will also approve NP's request to defer dealing with the disposition of the unbilled revenue increase reserve account. This issue will be dealt with as part of the Order arising from consideration of the Revenue Recognition Study to be filed by NP, as was intended in Order No. P.U. 36(1998-99).

39. The Board accepts NP's treatment of expenses associated with the 2000 and 2001 early retirement programs.

IX. REVENUE REQUIREMENT

40. The Board will use fiscal years 2003 and 2004 as the test years for determining revenue requirement, as proposed by NP.

41. The Board accepts the purchased power expense for the test year period 2003-2004, as proposed by NP, subject to any adjustments arising from this Decision.

42. The Board accepts the proposed operating expense forecast for the test year period 2003-2004, with the exception of executive compensation which is dealt with separately below.

43. The Board will no longer require NP to file an annual Advertising and Marketing Report.

44. The Board will direct that any STI payouts in excess of 100% of target payouts will be the responsibility of the shareholder, Fortis, and will be charged to non-regulated operations.

45. The Board accepts the level of executive compensation as part of NP's revenue requirement for the test year period 2003-2004.

46. The Board accepts the depreciation expense for the test year period 2003-2004, as proposed by NP.

47. The Board accepts the forecast income tax expense for the test year period 2003-2004, as proposed by NP, subject to any adjustments arising from this Decision.

48. The Board accepts the deduction from revenue requirement of other revenue for the test year period 2003-2004, as proposed by NP.

49. Since the Board will require that the 2001 Excess Revenue be rebated to customers, NP's revenue requirement will not be reduced by this amount, as proposed by NP.

50. The Board accepts the deductions from revenue requirement of non-regulated expenses for the test year period 2003-2004, as proposed by NP.

51. NP will be required to calculate and file a revised revenue requirement for 2003 and 2004 based on its proposals in this Application, and incorporating the changes set out in this Decision relating to allowed rate of return on rate base and the adjustment for 2001 Excess Revenue.

52. The Board will accept, subject to review of reasonableness and prudence, certain other secondary or incidental changes in revenue requirement which arise as a result of this Decision.

X. COST OF SERVICE

53. The Board has reviewed the Mediation Report and the evidence filed relating to Cost of Service issues. The Board accepts the recommendations of the parties as set out in the Mediation Report and will approve the recommendations as presented.

54. The Board will approve additional 2003 capital expenditures of $425,000 for a load research program, as proposed by NP.

XI. RATES, RULES AND REGULATIONS

55. The Board has reviewed the Mediation Report and the evidence filed relating to Rate Design Issues. With the exception of the issue relating to meter meading, which was not agreed to by the parties, the Board accepts the recommendations of the parties as set out in the Mediation Report and will approve the recommendations as presented.

56. Since the conclusion of the hearing of this Application, NLH has filed its general rate application for 2004. The Board will direct that scheduling of the consultation recommended in the Mediation Report on NLH's wholesale power rate design be considered at the pre-hearing conference for NLH's general rate application.

57. The Board will direct NP to propose to the Board for approval a *"peer group"* of utilities and performance measures upon which to evaluate NP's performance in accordance with the terms of the Mediation Report.

58. The Board will not direct any changes to the wording of Rules & Regulations 8-Meter Reading at this time. The Board will undertake a review of NP's meter reading program with a focus on the estimating methodology and process. This review will also include an assessment of existing regulatory and utility practice in other Canadian jurisdictions.

59. The Board will not make any adjustments to the application of demand charges within the General Service Rates.

60. The Board will not order the Domestic Rate be made available to house meters of apartment buildings.

61. The Board is not persuaded that changes to the Customer Deposit Policy or to the Rules and Regulations respecting security deposits would be fair to other customers. The Board will not order a change in the present policy covering the rate of interest paid to customers on cash security deposits.

62. The requirement for inspection of service prior to reconnection is primarily a safety issue and the Board will not intervene.

63. In order to finalize rates to be implemented as a result of this Application, NP will be directed to re-file, along with its revised revenue requirement and revised calculations of rate base and return on rate base, its Schedule of Rates, Tolls and Charges to be effective for billings on or after August 1, 2003 incorporating the decisions of the Board. The rates shall be calculated on the same basis as in the Application and shall be designed to remain in effect through 2004.

64. NP will also be directed to file a proposal as to the finalization of interim rates as set by Order No. 35(2002-2003) and the disposition of any variance between revenue generated based on these interim rates and the revised 2003 test year revenue requirement. The proposal should include a plan for the rebate of this amount to customers.

65. The Board will review NP's revised filing to ensure its decisions are appropriately incorporated and then issue a final Order, approving or modifying, as it deems appropriate, NP's rate base, NP's return on rate base and the revised rates for NP's customers as of August 1, 2003.

PART FOUR. BOARD ORDER

IT IS THEREFORE ORDERED THAT:

CAPITAL STRUCTURE

1. **The proportion of regulated common equity in the capital structure shall not exceed 45%. Regulated common equity in excess of 45% of the total invested capital shall not attract a rate of return higher than the rate of return on preferred equity of 6.31%.**

2. **For purposes of determining the weighted average cost of capital, the Board accepts the forecast average capital structure for the 2003 and 2004 test years as proposed by NP. The forecast average capital structure for 2003 shall be deemed to be debt of 54.28%, preferred equity of 1.45%, and common equity of 44.27%; and, for 2004, debt of 54.06%, preferred equity of 1.39%, and common equity of 44.55%.**

RATE BASE/RETURN ON RATE BASE

3. **NP shall move toward the adoption of the Asset Rate Base method for determining rate base and beginning in 2003 shall incorporate the average deferred charges, as set out in its Application, to the average rate base.**

4. **NP shall calculate and file a revised average rate base and return on rate base for 2003 and 2004, based on its proposals in this Application, incorporating the changes set out in this Decision and Order, which include:**
   i. **A return on regulated common equity of 9.75% is to be used for calculating the weighted average cost of capital for the 2003 and 2004 test years; and**
   ii. **The move to the Asset Rate Base method of determining rate base.**

5. **NP shall file annually with its capital budget application, unless otherwise ordered by the Board:**
   i. **Evidence relating to changes in deferred charges, including pension costs; and**
   ii. **A reconciliation of average rate base to average invested capital.**

6. **NP shall file no later than its next general rate application a report on including in rate base the remaining reconciling items between rate base and invested capital as described in this Decision and Order.**

7. **The allowed range of rate of return on rate base shall be 36 basis points for 2003 and 2004 and for use in the Automatic Adjustment Formula, unless otherwise ordered by the Board.**

AUTOMATIC ADJUSTMENT FORMULA

8. Unless the Board otherwise orders upon application by NP or by the Board of its own motion, the rate of return on rate base for the years 2005, 2006 and 2007 shall be set using the Automatic Adjustment Formula that was established by the Board in Order No. P. U. 36 (1998-99), incorporating the changes set out in this Decision and Order, including:

- **i. The move to the Asset Rate Base method; and**
- **ii. The use of the three most recent, rather than the two previously specified, series of long-term Government of Canada bonds in determining the risk-free rate.**

9. NP shall apply no later than November 30th in each of 2004, 2005 and 2006 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.

10. NP shall prepare and file with the Board:

- **i. With its annual return until otherwise directed by the Board, 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 period; and**
- **ii. With its annual return where in a year the actual rate of return on regulated equity is greater than 50 basis points above the cost of equity as determined by the Formula, a report explaining the circumstances and facts contributing to the difference.**

INTER-CORPORATE RELATIONSHIPS AND CHARGES

11. NP shall review and update its operating practices and procedures to reflect the principles governing all inter-corporate transactions as set out in this Decision and Order, and which may be amended by the Board from time to time.

12. NP shall file with the Board:

- **i. By June 30, 2004 a report addressing its stand-alone status in respect of the corporate credit linkage of NP to Fortis, as detailed by the Board in this Decision and Order.**

- **ii. By March 31, 2004 a report as to its operating practices and procedures relating to any and all inter-corporate transactions, including:**
    - **a) An investigation of the utilization of market rates or a suitable proxy markup for executive and management time charges;**

b) Quantification of the benefits to NP and its customers of its administration of and participation in a centralized insurance program for the Fortis Group of Companies and comparing these benefits to being insured on a stand-alone basis;

c) A comparison of NP's billing and collection practices with respect to affiliate companies and unrelated parties.

iii. Modified quarterly reports which show separately the associated labour and other staff and expense charges billed in relation to NP's insurance administration on behalf of Fortis and related companies.

ACCOUNTING TREATMENT AND POLICIES

13. NP's proposal to amortize the recovery of the $5,600,000 balance in the Hydro Production Equalization Reserve over a period of five years, beginning in 2003, is approved.

14. NP's proposal to adopt the market-related method of determining pension expense on a prospective basis, effective January 1, 2003, is approved.

15. The 2002 Depreciation Study and depreciation rates included therein are approved.

16. NP's proposal to amortize the depreciation reserve variance over the three-year period 2003-2005 is approved.

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

18. NP's proposal to amortize over a three-year period, beginning in 2003, regulatory costs of $1,200,000 is approved.

19. NP's request to defer dealing with the outstanding issues relating to the Revenue Recognition Study and the unbilled revenue increase reserve account is approved.

20. NP shall file with the Board:

i. A new depreciation study as of December 31, 2006;

ii. No later than with its next general rate application a report which addresses the use of the accrual method for other employee future benefits; and

iii. As part of its next general rate application a proposal as to the disposition of the balance in the Hydro Production Equalization Reserve as of December 31, 2005.

REVENUE REQUIREMENT

21. NP shall calculate and file a revised total revenue requirement for the 2003 and 2004 test years based on its proposals in this Application, incorporating the changes set out in this Decision and Order.

22. NP shall rebate to customers the 2001 excess earnings of $944,000 and shall file for the approval of the Board a proposal for this rebate.

23. NP's proposal for adjusting 2003-2004 revenue requirement to recover the outstanding amount of the 1992-1993 excess earnings as required by Order No. P.U. 36(1998-99) is approved, subject to any adjustments arising from this Decision and Order.

24. Regulated expenses for 2003 and subsequent years shall exclude short-term incentive program payouts in excess of 100% of target.

25. NP is no longer required to file the Advertising and Marketing reports required by Order No P. U. 7(1996-97).

COST OF SERVICE

26. NP shall revise its cost of service methodology, using the COS methodology as proposed by NP, incorporating the changes set out in this Order which include the recommendations of the Mediation Report, as set out in Schedule 1 of this Decision and Order.

RATES, RULES AND REGULATIONS

27. NP shall revise and file for the approval of the Board a revised Schedule of Rates, Tolls and Charges which shall be effective for monthly bills issued August 1, 2003 through to December 31, 2004, based on the proposals of NP in its Application, incorporating the changes set out in this Decision and Order, which include the recommendations of the Mediation Report as set out in Schedule 2 of this Decision and Order.

28. NP shall file a proposal as to the finalization of interim rates as set by Order No. P.U. 35(2002-2003) and the disposition of any variance between revenue generated based on those interim rates and the revised 2003 test year revenue requirement.

29. NP shall revise and file for the approval of the Board revised Rules and Regulations, based on the proposals of NP in this Application, incorporating the changes set out in this Decision and Order, which include the Recommendations of the Mediation Report as set out in Schedule 2.

30. **NP shall revise and file for the approval of the Board the definition of *"excess earnings"* in the company's system of accounts to reflect earnings above the maximum of the allowed range of rate of return on rate base.**

31. **NP shall file with the Board by March 31, 2004 a report suggesting a *"peer group"* of utilities and performance measures upon which to evaluate NP's performance, in accordance with the terms of the Mediation Report.**

CAPITAL ITEM

32. **The additional 2003 capital expenditure of $425,000 for a load research program as proposed by NP is approved.**

HEARING COSTS

33. **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 Section 117 of the *Act*.**

Dated at St. John's, Newfoundland and Labrador this 20th day of June 2003.

____

Robert Noseworthy,
Chair & Chief Executive Officer.

____

Darlene Whalen, P.Eng.,
Vice-Chairperson.

____

John William Finn, Q.C.,
Commissioner.

____

G. Cheryl Blundon,
Director of Corporate Services
and Board Secretary.

SCHEDULE 1

COST OF SERVICE

RECOMMENDATIONS OF

THE MEDIATION REPORT

ORDER NO. P. U. 19(2003)

COST OF SERVICE RECOMMENDATIONS OF THE MEDIATION REPORT

1. Newfoundland Power's ("NP's") cost of service study filed in this proceeding is fundamentally appropriate and in general compliance with Board Orders from previous hearings that have accepted NP's use of embedded cost of service studies as a guide in determining the revenue requirement increases or decreases to be applied to each class.

2. The following changes to NP's cost of service methodology, which received temporary Board Approval in NP's 1996 General Rate Proceeding, should be approved in this case:

   - Classification of NP's hydraulic plant using system load factor on energy rather than 100 per cent demand;
   - Allocation of NP's generating plant using a Single Coincident Peak allocation ("1CP") rather than Non-Coincident Peak allocation ("NCP");.
   - Allocation of NP's transmission plant using 1CP rather than NCP;
   - Allocation of purchased power transmission demand costs using 1CP rather than NCP;
   - Allocation of purchased power generation demand costs using 1CP rather than NCP;
   - Allocation of NP's funding of Newfoundland Hydro's rural deficit based on allocated class costs (with the rural deficit amount removed from determination of allocators to class cost).

COST OF SERVICE
RECOMMENDATIONS OF
THE MEDIATION REPORT

3. The Board should approve two additional changes to NP's cost of service methodology:

   - General expenses (i.e., General System Costs and Administration and General Costs) should be functionalized and classified based on the assumption that a portion of these costs is related to net utility plant (capital labor expense as a percentage of capital labor expense plus operating labor expense), rather than assuming (as previously) that all of these costs relate to operating and maintenance (O&M) expense.

   - The cost of service study should use normalized revenue and normalized purchased power expense rather than actual revenue and purchased power expense, unadjusted for normalization, as previously.

4. The Board should approve NP's use of an NCP allocation for distribution demand costs even though this differs from the 1CP allocator that Newfoundland Hydro was directed to use for distribution demand costs in Order No. P. U. 7(2002-2003).

SCHEDULE 2

RATES, RULES AND REGULATIONS

RECOMMENDATIONS OF

THE MEDIATION REPORT

ORDER NO. P. U. 19(2003)

RATES, RULES AND REGULATIONS
RECOMMENDATIONS OF
THE MEDIATION REPORT

1. The Board should approve tail block rate increases above the average class increase for Rates 2.2, 2.3 and 2.4 so as to better reflect short-run marginal energy costs in these tail block rates.

2. The Board should approve the elimination of minimum monthly ("ratcheted") demand charges, linked to the customer's maximum demand during the previous twelve months, in General Service Rates 2.2, 2.3 and 2.4.

3. The Board should retain the Curtailable Service Option Credit of $29/kva in Rates 2.3 and 2.4 and require NP to inform customers of the possibility of significant future changes in this credit.

4. The Board should approve NP's proposed merger of street light and area lighting rates for the 400W MV fixtures with the 250W HPS fixtures that replace them. The Board should also approve NP's proposed removal from the Schedule of Rates and Regulations, the charges for the 1,000W MV fixture, the 700W MV fixture, and the 150W HPS post top fixture, since these no longer exist on NP's system.

5. To the extent possible, there should be no adverse customer rate impacts. Any overall revenue change should be distributed equally to each class of customers. With the exception of any change in basic customer charges (see issue "9", below), no customer should have a rate change that produces an annual cost change that is more than twice the system average (unless the dollar impact is minimal).

6. The Board should approve a change to Regulation 9(o) to reduce the application fee for a customer name change from $14.00 to $8.00 (the current new service fee).

7. The Board should approve the removal of clause 9(n) to eliminate charges for the preparation of account statements for billing information prior to the most recent twelve months.

8. The Board should approve a change to Regulation 9(f) and a proposed new clause 12(g) permitting charging the reconnect fee to new customers in apartments where a reconnection is required subsequent to a request by a landlord to disconnect an apartment. Such customers will not be required to pay the new service application fee.

RATES, RULES AND REGULATIONS
RECOMMENDATIONS OF
THE MEDIATION REPORT

9. The current basic monthly customer charges for domestic (residential) service and small general service rate 2.1 should be reduced by $1.00. The revenue loss associated with this change should be made up by adjusting the energy component of these same rates so that the change does not impact customers in other rate classes. NP also agrees that (1) it will not propose a basic customer charge increase as a result of any wholesale rate increase in Hydro's 2003 GRA proceeding, and (2) in its next GRA, NP will cap the customer charge recovery of distribution costs allocated to customers at 50% of these allocated distribution costs for these rate classes, with the remainder to be recovered through energy charges. Distribution costs are distribution network costs beyond the service drop and do not include customer specific costs such as meters, meter reading, billing and service drops.

Application for Approval of Certain Revisions to its Rates, Charges and Regulations
NSUARB-NSPI-P-882, March 2006

DECISION **NSUARB-NSPI-P-882**
2006 NSUARB 23

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION by **Nova Scotia Power Incorporated** for approval of certain Revisions to its Rates, Charges and Regulations

BEFORE:

John A. Morash, C.A., Panel Chair
Roland A. Deveau, Member
Kulvinder S. Dhillon, P. Eng., Member

COUNSEL:

NOVA SCOTIA POWER INCORPORATED
James L. Connors, Q.C.
Rene Gallant

AFFORDABLE ENERGY COALITION
Claire McNeil
Megan Leslie

AVON VALLEY GREENHOUSES LTD., ***et al.***
Robert G. Grant, Q.C.
Nancy G. Rubin

CANADIAN MANUFACTURERS & EXPORTERS
Robert Patzelt

CONSUMER ADVOCATE
John P. Merrick, Q.C.
William L. Mahody

ECOLOGY ACTION CENTRE
Ceilidh Auger-Day

ELECTRICITY CONSUMERS ALLIANCE OF NOVA SCOTIA
John Woods, P. Eng.

GASWORKS ENERGY CORP.
John Reynolds, P. Eng.

HALIFAX REGIONAL MUNICIPALITY
Mary Ellen Donovan

DR. LARRY HUGHES, Ph.D

LIBERAL CAUCUS OFFICE (NOVA SCOTIA)
Danny Graham, MLA
David Macrury

MUNICIPAL ELECTRIC UTILITIES
OF NOVA SCOTIA CO-OPERATIVE
Albert Dominie

NEW DEMOCRATIC PARTY CAUCUS OFFICE
Howard Epstein, MLA

PROVINCE OF NOVA SCOTIA
(Department of Energy)
Stephen T. McGrath

STORA ENSO PORT HAWKESBURY LIMITED and
BOWATER MERSEY PAPER COMPANY LIMITED
George T. H. Cooper, Q.C.
David S. MacDougall

HEARING DATES: November 14-17, 22-25, 28-30 and December 1-2, 2005

FINAL SUBMISSIONS: December 22, 2005

LIST OF WITNESSES: APPENDIX - A

LIST OF INTERVENORS: APPENDIX - B

BOARD COUNSEL: S. Bruce Outhouse, Q.C.

DECISION DATE: March 10, 2006

DECISION: **Requested Revenue Requirement increase of approximately $106 million, after reflecting the natural gas settlement agreement, reduced to approximately $61 million; Proposed average rate increase for above-the-line customers of approximately 13%, reduced to approximately 8.6%, with an 8.9% increase for domestic customers, effective March 10, 2006; Annually adjusted rates to increase effective January 1, 2006, as determined by the Compliance Filing**

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Appendix - A	List of Witnesses
Appendix - B	List of Formal Intervenors
Appendix - C	Summary 2006 Cash Working Capital Requirement
Appendix - D	Conservation & Energy Efficiency Plan 2006 - Detailed Summary Table

1.0 INTRODUCTION

[1] This decision is further to a public hearing conducted by the Nova Scotia Utility and Review Board (the "Board") over 13 days between November 14, 2005 and December 2, 2005, in the matter of an application by Nova Scotia Power Incorporated ("NSPI", the "Company", the "Utility") for approval of revisions to its Rates, Charges and Regulations.

[2] NSPI is a regulated public utility and is the successor to Nova Scotia Power Corporation, a Crown Corporation which was privatized in 1992. As of January 1, 1999, NSPI became the principal subsidiary of Nova Scotia Power Holdings Incorporated, now known as Emera Incorporated ("Emera").

[3] NSPI is engaged in the production and supply of electrical energy. It distributes electricity through a province-wide system and, as at December 31, 2004, served approximately 468,000 customers, including six municipal electric utilities. Its revenues for the year 2004 were $935 million and its total assets, as at December 31, 2004, were $3.1 billion.[1]

[4] In its application, dated July 5, 2005, NSPI requested an increase in rates to meet its proposed revenue requirement. It has used its estimated expenses for 2006 as the test year for ratemaking purposes. The proposed rate increases result in an average overall increase of 14.7% across all above-the-line classes. On November 21, 2005, NSPI announced that it had reached an agreement with its supplier on pricing for natural gas

[1]Exhibit N-2, Appendix A

under an existing long-term natural gas purchase agreement, lowering its 2006 fuel forecast by $22 million. According to a News Release issued by NSPI on that date, the agreement reduces the proposed average rate increase to approximately 13% (Undertaking U-43).

[5] The public hearing was duly advertised in accordance with **sections 64** and **86** of the **Public Utilities Act**, R.S.N.S. 1989, c. 380, as amended (the "**Act**"), which read as follows:

> **Approval of schedule of rates and charges of utility**
> **64 (1)** No public utility shall charge, demand, collect or receive any compensation for any service performed by it until such public utility has first submitted for the approval of the Board a schedule of rates, tolls and charges and has obtained the approval of the Board thereof.
>
> **Filing with Board**
> **(2)** The schedule of rates, tolls and charges so approved shall be filed with the Board and shall be the only lawful rates, tolls and charges of such public utility until altered, reduced or modified as provided in this Act. R.S., c. 380, s. 64.
>
> **Notice of hearing of application for rate changes**
> **86** Notice of the hearing of any application, for the approval of or providing for an increase or decrease in the rates, tolls and charges of any public utility, shall be given by advertisement in one or more newspapers published or circulating in the cities, towns or municipalities where such changes are sought, for three consecutive weekly insertions preceding the date of said hearing, unless otherwise ordered by the Board. R.S., c. 380, s. 86.

[6] A total of 39 formal intervenors responded to NSPI's application. A number of these parties (identified in Appendix B attached) were represented at the hearing by Counsel. The Nova Scotia Department of Energy (the "Province"); the Consumer Advocate (the "CA"); Avon Valley Greenhouses Ltd. *et al.* ("Avon"), whose Counsel represented approximately 19 intervenors; Stora Enso Port Hawkesbury Limited and Bowater Mersey Paper Company Limited ("SEB"); Halifax Regional Municipality ("HRM"); Affordable Energy Coalition ("AEC"); Ecology Action Centre ("EAC"); Electricity Consumers

Alliance of Nova Scotia ("ECANS"); Canadian Manufacturers & Exporters ("CME"); GasWorks Energy Corp. ("GasWorks"); the Liberal and NDP Caucus offices; Dr. Larry Hughes; and the Municipal Electric Utilities of Nova Scotia Co-operative ("MEUNSC") all participated in the hearing. The Board also received numerous submissions from members of the public opposing NSPI's application.

[7] A significant part of NSPI's evidence involves the cost of fuel, particularly imported coal, as well as the projected benefit potentially earned by NSPI on the resale of natural gas. NSPI filed this information on a confidential basis. The Board imposed the precedent, established in the 2002 rate case and applied again in the 2005 rate case, which provides access to this information only to those intervenors who agree to sign confidentiality undertakings.

[8] As a result, certain testimony, undertakings, exhibits and transcripts are considered confidential and are accessible only to the Board and those parties who agreed to sign confidentiality undertakings. For the most part, redacted versions of this evidence are on the public record. In addition, certain of the hearing days relating to evidence on fuel were conducted on an *in camera* basis.

[9] In its 2002 decision the Board stated that:

> While conducting *in camera* sessions is an unusual occurrence for the Board, it is not precluded by the Board's regulatory rules. Indeed the rules contemplate information being filed in confidence and also provide for other parties to request its disclosure. The Board believes that its role as a regulator responsible for protecting the public interest requires it to issue a decision that is, in all respects, accessible to the public. The Board considers that it is unacceptable to issue two versions of a decision - one public and one confidential. Therefore, although the Board has carefully considered all of the evidence filed during this

> proceeding, including those parts which involve confidential information, the Board has chosen, in this decision, to avoid direct reference to confidential information.
>
> (Board Decision, October 23, 2002, p. 5)

[10] As it did in the 2005 rate case, the Board continues to believe that this is the most appropriate manner in which to issue a decision in a case where a significant portion of the evidence is confidential. Accordingly, to the extent possible, this decision will not refer directly to confidential information.

[11] The Board wishes to acknowledge, with appreciation, the contribution and participation of the intervenors, NSPI and the public in this proceeding. The significant work of the parties, as well as the expert witnesses appearing at the hearing, assisted the Board considerably in this process. The Board has reviewed, analyzed and considered many thousands of pages of material in its decision-making process.

2.0 BACKGROUND

[12] NSPI is a vertically integrated, investor-owned, regulated public utility with a virtual monopoly on electricity service throughout the Province. It is the primary electricity supplier in Nova Scotia, providing over 95% of the electricity generation, transmission and distribution in the Province.[2] The Board regulates NSPI in the public interest on a cost-of-service basis. The **Act** gives the Board broad regulatory oversight over public utilities and provides it with the authority to discharge its regulatory responsibilities. Some of the relevant statutory provisions are as follows:

> **Supervision of utility by Board**
> **18** 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 the said public utilities with the provisions of law and shall have the right to obtain from any public utility all information necessary to enable the Board to fulfil its duties. R.S., c. 380, s. 18.
>
> **Form of books and records of utility**
> **27** The Board may prescribe the forms of all books, accounts, papers and records required to be kept by any public utility and every public utility is required to keep and render its books, accounts, papers and records accurately and faithfully in the manner and form prescribed by the Board and to comply with all directions of the Board relating to such books, accounts, papers and records. R.S., c. 380, s. 27.
>
> **Examination and audit of accounts**
> **29 (1)** The Board may provide for the examination and audit of all accounts, and all items shall be allocated to the accounts in the manner prescribed by the Board.
>
> **Authority to inspect books or records of utility**
> **(2)** The agents, accountants or examiners employed by the Board shall have authority under the direction of the Board to inspect all and any books, accounts, papers or records and memoranda kept by any public utility. R.S., c. 380, s. 29.
>
> **Power to determine value of property of utility**
> **30 (1)** The Board may at any time, with the assistance of such engineers, accountants, valuators, counsel and others as it deems wise or advisable to employ, inquire into and determine the extent, condition and value of the whole or any portion of the property and assets of any public utility used and useful in furnishing, rendering or

[2] Exhibit N-25, IR-2, p. 9

supplying a particular service to or for the public, as of a date to be fixed by the Board.

Duty of utility to furnish information

33 (1) Every public utility shall furnish to the Board from time to time, and as the Board may require, maps, profiles, contracts, reports of engineers and other documents, records and papers, or copies of any and all of the same in aid of any investigation and to determine the value of the property of such public utility, and every public utility shall co-operate with the Board in the work of the valuation of its property in such further particulars and to such extent as the Board may direct.

Approval of improvement over $25,000

35 No public utility shall proceed with any new construction, improvements or betterments in or extensions or additions to its property used or useful in furnishing, rendering or supplying any service which requires the expenditure of more than twenty-five thousand dollars without first securing the approval thereof by the Board. R.S., c. 380, s. 35; 2001, c. 35, s. 30.

Separate rate base for each service supplied

42 (1) The Board shall fix and determine a separate rate base for each type or kind of service furnished, rendered or supplied to the public by a public utility.

Factors considered in establishing rate base

(2) In establishing a rate base the Board shall determine the value of the physical assets of the public utility in accordance with the provisions of this Act, including in such value the actual reasonable and necessary cost of labour and supervision up to and including gang foreman, and the Board may, in its discretion, make allowances for the following matters, and such other matters as the Board deems appropriate:

(a) necessary working capital;

(b) organization expenses to the extent of such sum as the public utility may establish to the satisfaction of the Board to have been reasonably and prudently expended out of capital account in respect of organization expenses as defined by the regulations of the Board;

(c) construction overheads to the extent of such sum as the public utility may establish to the satisfaction of the Board to have been reasonably and prudently expended out of capital account in respect of engineering, superintendence, legal services, taxes and interest during construction, and like matters not included in the valuation of the physical assets;

(d) expenses of valuations to the extent of such sums as may have been expended in respect of a valuation by the Board and, with the approval of the Board, charged to capital account;

(e) costs in whole or in part of land acquired in reasonable anticipation of future requirements.

Amortization of organization and valuation expenses

(3) The Board may direct that a public utility shall make such provision as to the Board seems proper for the amortization of the sums allowed in a rate base for organization expenses and expenses of valuations, and may direct that the sums required annually for such amortization shall be charged as an operating expense.

Revision of rate base

(4) The Board may from time to time revise any rate base making due allowance for extensions and additions to, improvements or alterations in and withdrawals or retirements from, the property and assets of the public utility.

Existing rate base

(5) Until a rate base is determined by the Board for any public utility pursuant to this Section, the present rate base for such public utility as from time to time revised or accepted by the Board shall continue in effect and shall be the rate base for such public utility, provided that the Board may direct that any such public utility shall make such provision as to the Board seems proper for the amortization of the sums allowed in such rate base for organization expenses, expenses of valuations or allowances not mentioned in subsection (2) and may direct that the sums required annually for such amortization shall be charged as an operating expense. R.S., c. 380, s. 42; 1992, c. 8. s. 35.

Orders by board respecting rates and charges of utility

44 The Board may make from time to time such orders as it deems just in respect to the tolls, rates and charges to be paid to any public utility for services rendered or facilities provided, and amend or rescind such orders or make new orders in substitution therefor. R.S., c. 380, s. 44.

Amount utility entitled to earn annually

45 (1) Every public utility shall be entitled to earn annually such return as the Board deems just and reasonable on the rate base as fixed and determined by the Board for each type or kind of service furnished, rendered or supplied by such public utility, provided, however, that where the Board by order requires a public utility to set aside annually any sum for or towards an amortization fund or other special reserve in respect of any service furnished, rendered or supplied, and does not in such order or in a subsequent order authorize such sum or any part thereof to be charged as an operating expense in connection with such service, such sum or part thereof shall be deducted from the amount which otherwise under this Section such public utility would be entitled to earn in respect of such service, and the net earnings from such service shall be reduced accordingly.

Earnings are in addition to expenses and allowances

(2) Such return shall be in addition to such expenses as the Board may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Board according to this Act and the rules and regulations of the Board. R.S., c. 380, s. 45.

Power to compel compliance by utility

46 The Board shall have power, after hearing and notice by order in writing, to require and compel every public utility to comply with the provisions of this Act and any municipal ordinance or regulation relating to said public utility, and to conform to the duties imposed upon it thereby by the provisions of its own charter, if any charter has or shall be granted it, provided, that nothing herein contained shall be held to relieve any public utility or its officers, agents or servants, from any punishment, fine, forfeiture or penalty for violation of any such law, ordinance, regulation or duty imposed by its charter, nor to limit, take away or restrict the jurisdiction of any court or other authority which now has or which may hereafter have power to impose any such punishment, fine, forfeiture or penalty. R.S., c. 380, s. 46.

Duty to furnish information

51 (1) Every public utility shall furnish to the Board all information required by it to carry into effect the provisions of this Act, and shall make specific answers to all specific questions submitted by the Board.

Duty to furnish safe and adequate service

52 Every public utility is required to furnish service and facilities reasonably safe and adequate and in all respects just and reasonable. R.S., c. 380, s. 52.

Approval for transfer of undertaking

62 Notwithstanding the provisions of any Act of the Legislature, no public utility shall sell, assign or transfer the whole of its undertaking or any part thereof to any person or corporation except with the approval of the Board first had and obtained. R.S., c. 380, s. 62.

Approval of schedule of rates and charges of utility

64 (1) No public utility shall charge, demand, collect or receive any compensation for any service performed by it until such public utility has first submitted for the approval of the Board a schedule of rates, tolls and charges and has obtained the approval of the Board thereof.

Filing with Board

(2) The schedule of rates, tolls and charges so approved shall be filed with the Board and shall be the only lawful rates, tolls and charges of such public utility until altered, reduced or modified as provided in this Act. R.S., c. 380, s. 64.

Equal rates and charges for similar services

67 (1) 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, and the Board may by regulation declare what shall constitute substantially similar circumstances and conditions.

Contravention prohibited

(2) The taking of tolls, rates and charges contrary to the provisions of this Section and the regulations made pursuant thereto is prohibited and declared unlawful. R.S., c. 380, s. 67.

[13] NSPI last filed an application for a general rate increase in June of 2004. The hearing was held between November 2004 and January 2005, and the Board's decision was issued on March 31, 2005. Certain findings in the 2005 rate decision, which are relevant to this case, can be summarized as follows:

- The Board reduced NSPI's revenue requirement by $53,244,000 million (approximately $70 million considering tax impacts) for the 2005 test year, which resulted in an average rate increase of approximately 5.3% for above-the-line customers, with an estimated rate increase of approximately 6.1% for most of these customers, including domestic customers, effective April 1, 2005. NSPI had proposed an average overall rate increase of 12.4% across all classes;

- The Board approved a 10.4% rate increase for all below-the-line customers, effective January 1, 2005;

- A settlement agreement proposed by NSPI was not approved, primarily due to the Board's concerns that its acceptance would cause the significantly higher cost of fuel projected by NSPI to be deferred to the expense of ratepayers either in 2005 or in later years;

- The common equity ratio for ratemaking purposes was increased from 35% to 37.5%;

- The Board approved a return on equity at 9.55% for the purpose of setting rates, with the earnings range set at 9.30% to 9.80%;

- The Board directed NSPI to use a return on rate base methodology for its next rate application rather than its long-standing practice of determining the return on the equity portion of total capitalization;

- NSPI was found to be imprudent by the Board in its imported coal procurement practices by failing to address these issues quickly, or efficiently enough, following the 2002 rate decision, to adequately protect itself or its ratepayers. As a result, the Board directed that the cost of fuel and purchased power approved for the 2005 test year be reduced by $18 million to reflect this imprudency;

- NSPI was directed to promptly engage high level in-house expertise to lead the imported coal aspect of its fuel procurement process and to establish a more efficient and accountable decision-making structure with respect to fuel procurement;

- Given the imprudence and inadequacies in NSPI's fuel procurement practices, the Board determined it inappropriate to approve a fuel adjustment mechanism;

- The Board determined that **s. 21** taxes should be deferred for 2005 and 2006, and that they be amortized over an eight year period commencing in 2007. This resulted in an actual reduction in NSPI's 2005 revenue requirement of approximately $32.7 million;

- The proposed increases for miscellaneous charges were found to be too high and were limited by the Board to an increase equal to the average rate of increase for above-the-line rates, rounded to the nearest dollar;

- The Board determined that it does not have the statutory authority to approve a rate assistance program to help low-income customers meet their electricity costs;

- The Board directed NSPI to initiate a technical conference process, with interested parties and stakeholders, to pursue an improved and effective demand side management program.

3.0 FUEL ISSUES

3.1 General Overview

[14] In its Notice of Application and Direct Evidence, NSPI indicated that this rate case is substantially about 2006 fuel costs, and it indicated that "... As is the case with similar utilities throughout North America, Nova Scotia Power and its customers are facing increasing costs for solid fuels, natural gas and oil driven by high and volatile global energy markets".[3]

[15] NSPI pointed out that customer rates approved for 2005 are based on a fuel and purchased power budget of $359 million. It expects that the fuel expense for the 2006 test year will be $120 million higher, for a total expected fuel and purchased power cost of $479 million. This amount is shown in Table 2, Appendix A of Exhibit N-2.

[16] Given the magnitude of the projected increase in fuel costs and its impact on rates, all aspects of NSPI's fuel procurement strategy, policies, procedures and cost estimates were subject to thorough scrutiny at the hearing.

[17] The Liberty Consulting Group ("Liberty") was engaged by Board Counsel and carried out a comprehensive review of NSPI's fuel procurement strategy, policies, procedures and cost estimates, just as it had in connection with the previous rate application. In its Direct Evidence, Liberty sets out the key points in its evidence:

Fuel Forecasting

- Prices in the fuel market are cyclical, volatile, and difficult to predict with a substantial degree of certainty.

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[3]Exhibit N-1, p. 7

- We continue to believe from the information made available that NSPI has chosen a near-term emission-requirements path of procuring and burning low sulfur coal from the international market in its generating stations.
- Fuel management strategies must recognize the unpredictable nature of the fuel markets.

Fuel Management

- Fuel management encompasses all fuels for power generation, from the initial stages of planning, through development of strategies, procurement, fuel transportation, contract administration, and inventory management. Fuel management includes optimization evaluations of capital expenditures related to fuel use, and balancing fuel mixes among generating stations. It also requires the existence and use, in supporting fuel procurement decisions, of tools and models sufficient to allow sound consideration of the comparative costs of producing electrical energy at the bus-bar, consistent with reliability, environmental requirements, and legal considerations.
- NSPI has since the last case made substantial progress in addressing the fuel management weaknesses that we observed. A number of important challenges remain to be met, however, in satisfying itself and the Board that a full range of necessary capabilities exists.

    - NSPI has significantly improved its Fuel Procurement Policies and Procedures, but there are still opportunities for improvement
    - NSPI has significantly improved its fuel procurement portfolio strategy
    - NSPI has made satisfactory progress in beginning to build its new fuel supply portfolio, but must continue to make commitments to bring about its intended results
    - NSPI has made satisfactory progress in improving the image it conveys to the coal supply market
    - NSPI has satisfactorily resolved Liberty's organization-structure concerns from the prior case
    - NSPI has not sufficiently improved its procedures for fuel hedging
    - NSPI does not appear to have the necessary procedures for the procurement of purchased power
    - NSPI has not demonstrated a use of modeling in long-term coal supply analyses sufficient to evaluate fully such issues as fuel switching costs, or system generating unit changes, to comply with the lower SO_2 cap
    - NSPI has made some improvements in its fuel procurement model, but still cannot demonstrate that it is procuring fuels that will result in the lowest possible cost of electrical energy delivered to the bus-bar
    - NSPI has not demonstrated a satisfactory contract administration system, that it has conducted the appropriate reviews of fuel procurement solicitations, or that the appropriate levels of management have reviewed and approved procurement decisions and commitments.

2006 Fuel Cost Review

- Volatility in market prices for fuel used for electricity generation has continued and market prices have increased substantially since the last case.

- There is substantial reason to believe that this volatility will remain in the period during which NSPI will collect the rates to be established in this proceeding.
- Such volatility will create a substantial risk of over or under recovery of costs.
- That risk exists, no matter how sound the methods and the application of them to forecasts by NSPI.
- NSPI continues to suffer significant harm from past failure to adopt a robust portfolio strategy; not making sufficient long-term fuel commitments as far back as 2002 will continue to cause 2006 fuel costs to be higher than they should be.
- The magnitude of that harm has not diminished as much as might have been expected in light of NSPI's change to a portfolio strategy, because 2006 fuel costs now appear to be significantly higher than they did during the last case.
- NSPI's estimate of its 2006 solid fuel costs has turned out to be too high, as recent NSPI purchases have reduced the amount of uncommitted tonnages and at prices less than NSPI had estimated.
- **[confidential]**
- NSPI's arrangement with affiliate Emera Energy Services ("EES") for the sale of excess NSPI natural gas does not comport with standards of arm's-length dealing with affiliates, good utility practice, or the Board's 2002 decision addressing NSPI's use of an affiliate for off-system gas sales.
- There were a number of anomalies in the solicitation process that NSPI used to select EES as the entity to purchase its excess natural gas; the documentation provided by NSPI indicates favoritism to EES.
- It would be reasonable for NSPI to sell its excess natural gas directly to a broader market **[confidential]**; at the least, NSPI should conduct arm's-length, competitive solicitations for its gas sales.
- NSPI's forecast of the total cost of its HFO requirements for 2006 appears reasonable; however, this conclusion must be qualified because of questions about affiliate purchases and sales.
- There appear to have been substantial levels of sales and purchases of heavy fuel oil between Emera Fuels; the available documentation indicates that NSPI did not follow normal processes with respect to competitive purchasing practices and management approvals.

(Exhibit N-97, pp. 5-9)

[18] Based on its review, Liberty made the following recommendations:

Planning

1. NSPI should immediately conduct an overall re-evaluation of its generating system to determine the optimum way of meeting new requirements for control of SO_2 emissions, as well as emissions of other pollutants of concern, from its generating plants. Such re-evaluation should incorporate a long-term view, not just the next several years. The recommended study should consider not only all fuel supply options, but also integration of fuel supply options with capital expenditures for alteration, modification, or expansion of its generating units, in order to achieve the lowest possible costs for generation of power, consistent with reliability, environmental concerns and legal considerations.

Organization and Procedures

2. NSPI should develop a more comprehensive set of fuel hedging policies and procedures that measure up to industry standards.

3. NSPI should develop a complete set of procedures for the procurement of purchased power.

4. NSPI should continue to refine its own internal spreadsheet model for fuel procurement in order to bring it to a level of sophistication that permits evaluation of fuel-supply options and procurement decision-making on the basis of procuring that mix of fuels that will result in producing the lowest possible cost of electrical energy delivered to the bus-bar.

5. NSPI should continue to revise and refine the Fuel Procurement Policies and Procedures to resolve the concerns expressed in this testimony.

6. NSPI should continue to tighten the controls on the overall fuel procurement process so that proper, readily available documentation demonstrates clearly that appropriate levels of senior management, including the Fuel Strategy Table, have reviewed and approved recommendations made to them regarding specific fuel procurement decisions.

Fuel Supply Portfolio

7. NSPI should continue to build the fuel supply portfolio so that the parameters currently set forth by NSPI in its Fuel Procurement Policies and Procedures are achieved by December 31, 2007.

. . .

Affiliates

11. NSPI should immediately bid on a fully competitive and arm's-length basis its sale of excess natural gas for a one-year term, and should arrange for and coordinate that bidding and the cancellation of the existing agreement with EES with all reasonable dispatch. No costs associated with the termination of the agreement with EES should be included in customer rates.

12. NSPI should also promptly conduct a complete and objective study of the net economic and other impacts of establishing an in-house capability to perform this sale function. The study should take into account likely future gas purchases and internal use and it should quantify the differential economics of a full range of options. It should be filed with the Board within six months, and NSPI should specifically seek Board approval of the approach it intends to use (*e.g.,* asset management, internal function, operation by NSPI within/without Canadian markets) to sell excess gas after the expiration of the new one-year contract that we recommend be put out for competitive bid as promptly as possible.

13. There needs to be a comprehensive audit of affiliate transactions directly and indirectly affecting NSPI fuel procurement, sales, and costs, in order to verify that such transactions are not adversely affecting utility fuel costs.

(Exhibit N-97, pp. 9-12)

[19] Fuel experts retained by SEB and Avon echoed some of the same concerns and criticisms as Liberty and added a few more of their own. As is readily apparent, therefore, there are several important fuel related issues which the Board must address.

3.2 Fuel Procurement Strategy

3.2.1 Overview

[20] As a result of the Board's 2005 rate decision with respect to the 2005 rate application, NSPI has made a number of changes with respect to its fuel procurement strategy, policies and procedures. NSPI, in its Direct Evidence, sets out these changes:

> The Board made several findings and issued directives concerning fuel procurement. NSPI has been asked to file a report with the Board within six months of the 2005 decision "outlining the implementation of the changes" directed by the Board. That report will be filed by September 30, 2005. Meanwhile, having listened to concerns of the Board and customers, NSPI has worked to:
>
> • Reorganize its fuel procurement function so that there is a single individual responsible for both the commercial and strategic aspects of fuel procurement. The Director, Energy, Fuels & Risk Management has an extensive background with NSPI and brings valuable experience to this position. He reports to the General Manager, Power Production who in turn reports to the Chief Operating Officer of NSPI. This organizational structure provides more efficient and accountable decision-making with respect to fuel procurement.
>
> • Engage the services of an executive recruitment firm, STM Associates of Salt Lake City, Utah to identify candidates with experience in international coal markets and coal procurement for employment with NSPI to lead the imported coal supply aspect of the Company's coal procurement. Presently NSPI is screening candidates and expects that the successful individual would be in the position by September of 2005. The selected candidate will report to the Director, Energy Fuels and Risk Management. In the interim, the fuel procurement strategy has been developed and

is being executed with the ongoing assistance of Energy Ventures Analysis Inc. In addition to its work in developing the fuel procurement strategy, EVA independently evaluates all solid fuel supply bids and participates on the Fuel Strategy Table.

• Revise its Policies and Procedures Manual to incorporate both specific comments and general concerns identified by the Board and other intervenors during the 2005 rate proceeding including:

○ Revising its policy statements regarding objectives to more clearly indicate NSPI's commitment to a portfolio strategy and to the evaluation of purchased fuels based upon a quality adjusted valuation on a system-wide basis; and

○ Defining a detailed portfolio strategy.

• Commit to further expanding its procurement portfolio to include multi-year commitments for low sulphur coal imports. To that end, NSPI solicited the market for multi-year offers in January and April 2005....

• Reconstitute its Fuel Strategy Table so that the Vice President, Emera Energy Services no longer participates. This will address concerns related to potential conflicts of interest between Emera and NSPI.

. . .

(Exhibit N-1, pp. 43-44)

[21] The issue is whether the changes described by NSPI, adequately address the problems identified in the 2005 rate decision.

3.2.2 Submissions - NSPI

[22] NSPI states that its objective, with respect to its Fuel Procurement Strategy, "... is to procure and manage a reliable and competitively-priced supply of fuel for its generation fleet consistent with regulatory and environmental requirements. This objective incorporates NSPI's use of renewable energy such as hydro, wind, tidal, biomass as well as demand side management." It goes on to state that it will achieve this objective with "...

first, a solid fuels procurement portfolio that consists of a combination of long and medium term agreements that collectively account for between 70 to 80 percent of its annual solid fuel procurement and, second, a HFO and natural gas procurement strategy that allows NSPI to maximize the value of its long-term purchase contract for natural gas by consuming or selling the natural gas (and buying HFO) when it is economic to do so. NSPI further intends to complement its physical portfolio of fuels with appropriate financial hedges that are currently available or might become available in the future."[4]

[23] For purposes of its portfolio strategy, NSPI defines short-term agreements as being for one year or less; medium-term as being between one and four years; and long-term as being greater than four years.[5]

[24] NSPI indicates in its Direct Evidence that it plans to continue to expand and refine its portfolio to:

- Provide a reliable source of competitively-priced fuels to the NSPI generating fleet that meet regulatory and environmental requirements;
- Maintain a portfolio of long, medium, and short-term agreements that provide for supply and supplier diversification with credit worthy counter-parties;
- Manage market volatility through agreements with staggered expiration dates, volume options, and varied pricing mechanisms;
- Maximize competition among suppliers by qualifying as many sources as possible;
- Buy Nova Scotia coal should competitive supplies of suitable quality be available; and

[4]Exhibit N-1, pp. 44-45

[5]Exhibit N-1, p. 45

- Review commitments on an on-going basis.

(Exhibit N-1, p. 47)

[25] In a response to an Information Request from the Province, NSPI stated:

> NSPI moved quickly to implement the Board's directives regarding fuel procurement. Since the 2005 Rate Decision received by NSPI on March 31, 2005, NSPI has made the following changes:
>
> - Mr. Todd Sattler, VP Energy Services, ceased to participate in NSPI's Fuel Strategy Table immediately on receipt of the Board's decision. Also, Mr. Chris Huskilson no longer participates in the FST as of August, 2005.
> - Mr. Mark Sidebottom was appointed to the position of Director, Energy, Fuels, and Risk Management. Within this role, Mr. Sidebottom takes on responsibility for both the strategic and commercial aspects of fuel procurement, ensuring that a single person is accountable for both.
> - NSPI has established a more efficient and accountable decision-making structure.
> - The Fuel Procurement Policies and Procedures Manual has been revised to address the Board's directives from the 2005 Rate Case Decision, as well as the preferences expressed by customers. The Manual reflects the intention to reduce fuel price volatility and develop a portfolio with increased long and medium-term contracts, and
> - NSPI has been working diligently to recruit high level in-house expertise to lead the imported coal supply aspect of its fuel procurement process, and with the assistance of a world-wide executive recruiter the process is nearing its final stages.
>
> (Exhibit N-72, NSDOE IR-91, Attachment 1, p. 24)

[26] In its Rebuttal Evidence filed with the Board on November 8, 2005, NSPI requested Board approval of the Fuel Procurement Strategy:

> In the short period since the end of the last rate case, NSPI has worked expeditiously to update its policies and procedures manual in order to respond to the concerns of the Board and customers.
>
> In general, the revised policies and procedures manual along with the restated procurement policy has received favourable reviews. Remaining areas of concern to Liberty are the hedging policy, and documentation. NSPI commits to further refining its hedging policies and

procedures in concert with Liberty or alone as the Board sees fit and to providing whatever procurement documentation the Board determines is appropriate.

NSPI requests an endorsement from the Board of the procurement policies and procedures as set out in the Manual filed with the Board in September.

(Exhibit N-153, pp. 52-53)

[27] In its Closing Argument, NSPI requests that the Board approve its Fuel Procurement Policies and Procedures Manual, and that the Board confirm that the strategy is being appropriately implemented.

3.2.3 Submissions - Liberty and Intervenors

Liberty

[28] With respect to NSPI's fuel procurement strategy, Liberty's Direct Evidence stated that:

NSPI has made significant, positive change to its fuel portfolio strategy. The new strategy is clear, does away with the limitation of contract lengths, and provides for longer term contracts with staggered expiration dates. The new approach eliminates the central theme of the old, speculative strategy, which was to stay close to the market, which we saw as a euphemism for spot purchases. The essential points of the new strategy are that NSPI will seek to:

- Maintain a portfolio of long-, medium-, and short-term agreements that provide for supply and supplier diversification with credit-worthy counterparties
- Reduce the effects of market volatility through agreements with staggered expiration dates, volume options, and varied pricing mechanisms
- Maximize competition among suppliers by qualifying as many reliable, creditworthy, and geographically diverse sources as possible
- Buy Nova Scotia fuels, if available, based on price and quality
- Review commitments in order to determine whether renegotiations would be appropriate in the context of a changed market

- Build relationships with suppliers and counterparties based on credible performance

. . .

The exact components of the portfolio may vary over time in response to the market and other events. NSPI has already begun to build its solid fuel portfolio, and states that it desires to achieve its target portfolio percentages over the next 24 months. NSPI recognizes that this schedule may need to be extended, should there be limited supplier interest in longer-term agreements.

NSPI's new strategy is reasonable, and responds well to Liberty's recommendations in the prior case. We also recognize that a portfolio cannot be built instantly, but will take time to assemble, cautioning that the issue of time lag begs the question of when the construction of such a portfolio should have begun.

NSPI's April 2005 solicitation sought **[confidential]** tonnes per year of long-term low-sulfur coal supply through 2008. NSPI recognized this solicitation as its first attempt to add a long-term solid fuel supply contract to its portfolio, in response to the Board's March 2005 decision. NSPI properly handled the solicitation, including a sufficient number of qualified potential suppliers, conducting bid evaluations, and making a decision that appears sound from the information that NSPI provided. NSPI procured the least-cost supply offered. This procurement was the only long-term solid-fuel supply agreement entered during the 2004/2005 period, but NSIP[sic] did make shorter term purchases.

Liberty did find, however, that the documentation supporting this decision failed to demonstrate approvals by the required level of management. The documents contained a page representing decisions of the Fuel Strategy Table and showing its approval. The documentation, however, was not in the form of official minutes of the Fuel Strategy Table, and did not contain any formal signatures authorizing the procurement. Liberty found the same deficiency in the majority of solicitations that NSPI conducted in 2004 and 2005. In no case were formal minutes of the Fuel Strategy Table included in what NSPI provided in response to Liberty's request for procurement documents.

The solid-fuel procurement commitments that NSPI has now made move it in the proper direction in increasing the percentage of supply from long-term contracts. The following table demonstrates the current solid fuel percentages (bases [sic] on 2005 tonnages) compared to the target solid fuel percentages. NSPI finds itself presently below target for long- and medium-term solid fuel contracts. However, we believe that its pace is reasonable, again subject to the concern about when NSPI began to implement this approach.

. . .

NSPI has established an appropriate fuel supply portfolio strategy, and has taken substantial efforts in building a portfolio that corresponds to it. The short time since the decision in the prior case addressing assembly of this new portfolio makes understandable that the portfolio is not yet fully assembled. NSPI has stated that it intends to complete assembly of the desired portfolio in approximately 24 months; Liberty feels that every effort should be made to accomplish this objective.

. . .

NSPI has acted effectively and timely in developing and implementing its new portfolio strategy. The strategy appropriately responds to Liberty's recommendations from the prior

> case and includes an appropriately defined mix of long-term, mid-term, and short-term fuel contracts. NSPI's implementation of this strategy is acceptable, considering the time available since the Board's decision from the prior case in March 2005.
>
> (Exhibit N-97, pp. 29-32 and p. 35)

[29] With respect to NSPI's fuel procurement policies and procedures, Liberty expressed concerns about the lack of management approvals concerning total tonnages to be acquired for the 2006 commitment, and concluded that there is a lack of "proper contract administration systems" at NSPI.[6]

[30] Liberty's overall conclusions with respect to coal procurement and supply in 2005 and beyond are as follows:

> ... We found that NSPI has improved its solicitations, and that it has corrected the RFP language concerns we had observed in the last case. NSPI's solicitations have become more precise in communicating what NSPI actually wants in terms of tonnages and years of delivery. These improvements respond well to concerns that Liberty expressed in the last case.
>
> Liberty requested that NSPI provide the detailed evaluations associated with solicitations; in many cases it provided only those performed by EVA. Liberty realizes that NSPI is in a transition period, but believes that NSPI must move in the immediate future to develop and use the capability to conduct such evaluations with internal resources. Liberty believes that NSPI should make such internal evaluations the norm as soon as its new Senior Manager Solid Fuels is on-board and up to speed. Liberty emphasizes that its concern in this respect is administrative and not substantive. Our review of the bids disclosed no reason to conclude that NSPI failed to make a sound decision on which bidder to select.
>
> We emphasize, however, that attention to detail is essential to maintaining good performance in the long run. Our experience demonstrates that there is a point, which is hard to define objectively, at which the degree of inattention to administrative and procedural matters becomes great enough to create concerns about the quality of substantive decisions and job performance.
>
> We observed a number of other cases that fall into this category. Liberty requested that NSPI provide documentation reflecting the securing of management approvals necessary for procurement. NSPI provided only sketchy and incomplete information in response. Most procurements included a "Record of Decision" from the Fuel Strategy Table, but in no case did Liberty find minutes of Fuel Strategy meetings, or NSPI management signatures

[6] Exhibit N-97, p. 44

> indicating approval to proceed with commitments to suppliers. Most files contained copies of commitment letters signed by the NSPI Solid Fuels Commercial Manager or the Solid Fuels Operation Manager. The authority of these individuals, however, does not extend to the commitments as large as those for which they signed, absent written documentation with accompanying signatures from upper management.
>
> Typically, Liberty finds that utilities provide copies of procurement documentation approvals containing actual signatures of management, and of management committee personnel, indicating that, in logical sequence, management has seen, reviewed, and approved the evaluations and recommendations that led to the actual commitment of procurement from any given fuel supplier.
>
> (Exhibit N-97, pp. 44-46)

[31] Liberty also examined NSPI's procurements of purchased power, fuel oil, and natural gas. With respect to purchased power, Liberty indicated that the forecasted power purchases for 2005 and 2006 were not under contract. NSPI makes purchases on an hourly basis as needed to supplement the most economic running of its generation fleet. Liberty expressed concern that NSPI "...does not appear to have any procedures governing the procurement of purchased power."[7] Without such procedures, Liberty is not able to determine whether or not the procurement of purchased power is being managed and controlled effectively.

[32] With respect to fuel oil and natural gas, Liberty stated that, as a share of the generation fuels mix, its use is expected to rise from 16.4% in 2004 to 17.8% in 2006. Liberty indicated that from 2000 to late 2003, NSPI "...alternated between HFO and gas in the Tufts Cove steam units, depending on the delivered cost of HFO relative to the proceeds of selling the gas into the U.S. market. Since November 2002, however, the

[7] Exhibit N-97, p. 50

proceeds from selling the gas have been high enough to justify regular sale of gas and HFO burning at Tufts Cove."[8]

[33] With respect to NSPI's Fuel Procurement Policies and Procedures Manual, according to Liberty, NSPI has made significant changes and has shown a solid commitment to improvement. However, Liberty expressed concern that "...it has taken longer than it should have to make changes. Moreover ... the lateness in making the changes make it impossible to determine how well they will be implemented....Only the passage of time under them, which has not yet happened, will allow insight affecting that question."[9]

[34] Liberty indicated that its major concerns in the last rate case concerning fuel procurement and the portfolio strategy have now been satisfactorily resolved with the new procedures. However, it stated that there are five areas not yet fully resolved by the new procedures, and these are:

- No indications of responsibility for preparation of management reports
- Continued frequent solicitations for low-sulfur import coals
- No indication of supplier performance measures that are important
- Improved, but still insufficient procedures on hedging
- Problematic procedures on coal inventory measurement

(Exhibit N-97, p. 90)

[8] Exhibit N-97, p. 52

[9] Exhibit N-97, pp. 89-90

[35] Liberty also expresses concern that NSPI will use long-term solicitations to obtain coal pricing information rather than to seriously undertake actual fuel procurement, and the solicitations may be issued too frequently. Such solicitations may send the wrong message to potential fuel suppliers who "...will lose interest in submitting prices when they begin to suspect lack of intent to enter commitments...."[10]

SEB

[36] SEB, in its Closing Argument, states the following concerning the Fuel Procurement Policies and Procedures Manual:

> It became apparent during the proceeding that NSPI is seeking to have the Board approve its Fuel Procurement Policies and Procedures Manual (the "Manual") (Ex. N-167) as filed on September 14, 2005. Furthermore, in particular NSPI is seeking to have its Fuel Procurement Strategy set out at Section 1.2 of the Manual approved by the Board.
>
> SEB respectfully submits that this is inappropriate at this time, and would essentially be providing NSPI with a "blank cheque" with respect to fuel procurement. In particular, as NSPI has yet to hire the high level in-house expertise which the Board ordered in its 2005 Decision, whoever may eventually fill that role has had no input into the Manual or the Strategy contained in the Manual.
>
> If the Board grants NSPI the approval it is requesting, it appears that NSPI would then argue in all future rate proceedings that as long as it was within the parameters of the portfolio strategy set out in the Manual, its procurement decisions would not be subject to challenge. NSPI has simply not demonstrated to date that it can be given such latitude.
>
> . . .
>
> Although both Mr. Marston and Mr. Gubbins concede that in the long term and rationally applied, NSPI's portfolio approach is a reasonable step towards building a prudent fuel procurement strategy, the evidence of neither suggests that NSPI is yet near this stage. Further, the continuing lack of in-house expertise with respect to solid fuel procurement strongly mitigates against the Board granting any approvals with respect to the Manual or NSPI's proposed Strategy at this time.
>
> (SEB, Final **Confidential** Fuel Related Argument, pp. 56-57)

[10]Exhibit N-97, p. 91

Avon

[37] Avon, in its Closing Submission, refers to Dr. Manfred Raschke's, of International Strategic Information Services, criticism of the lack of transparency of the decision-making process concerning the fuel procurement procedures, and stated the following:

> At no time did NSPI produce Minutes of the FST meetings or NSPI management signatures indicating approval to proceed with commitments to suppliers. Instead, there are memos from EVA evaluating procurements and in certain circumstances "a record of decision". However, even the EVA records demonstrate a certain casual approach to record keeping and it is unclear whether the memos had been received, reviewed and considered before or after the FST meeting where the dates do not correspond with procurements and decisions.
>
> There continues to be an absence of experience in international coal procurement on the FST. NSPI has been diligent in keeping the Board and Intervenors updated with respect to its efforts to retain in-house expertise. We offered as a suggestion during the course of the hearing that with a continued lack of success in this regard, other options may be considered such as secondment of an individual within NSPI to another organization where he or she could "apprentice" the trade. We also encourage NSPI to identify and address any barriers to retaining an expert in-house.
>
> NSPI is seeking the Board's endorsement of its Fuel Procurement Policies and Procedures Manual. Whether or not the Board chooses to approve the particular document, it is clear that judgment is required at every step of implementation of the policy – the timing for tenders, the volumes to be tendered, and the make up of the fuel mix. This was conceded in cross-examination of Mr. Tedesco.
>
> (Avon, Redacted Closing Submission, p. 22)

[38] In concluding, Avon stated that:

> With respect to NSPI's Fuel Procurement Policies and Procedures, NSPI should be directed to improve upon its procedures for documenting decisions and recommendations and it should continue with its efforts to retain in-house expertise or develop expertise through secondment or other means.
>
> (Avon, Redacted Closing Submission, pp. 59-60)

[39] Avon, in its Rebuttal Submission, went a step further and submitted that the Fuel Procurement Policies and Procedures Manual should not be approved.

[40] Avon stated that:

> NSPI is looking for specific approval of its Fuel Procurement Policies and Procedures Manual. In their pre-filed evidence, Messrs. Antonuk, Spangenberg and Adger discussed their review of the revised Fuel Procurement Policies and Procedures Manual as filed on September 19, 2005. This Board will recall Liberty's testimony in the prior case and its detailed recommendations with respect to NSPI's fuel procurement policies. It is evident that NSPI has made strides in establishing its Manual and developing a portfolio approach, however deficiencies remain.
>
> Liberty stated with respect to the new Manual:
>
> > Liberty's testimony in the prior case listed 19 specific deficiencies in fuel procedures. The new procedures have satisfactorily resolved 14 of them. Our major concerns about objectives of fuel procurement and portfolio strategy have been satisfactorily resolved in the new procedures. The five areas not fully resolved by the new procedures include:
> >
> > - No indications of responsibility for preparation of management reports.
> > - Continued frequent solicitations for low sulphur import coals.
> > - No indication of supplier performance measures that are important.
> > - Improved, but still insufficient procedures on hedging.
> > - Problematic procedures on coal inventory measurement.
>
> Furthermore, as pointed out by the Liberty Group, while the adoption of policies and procedures is a good first start, what is more important is whether the policies are communicated and used with rigour. Because of the lateness in implementing the changes, neither Liberty nor the Board has been able to determine how NSPI will operate under its new Manual.
>
> We have pointed out in our submissions of December 14, 2005, our concerns with respect to the lack of transparency of the decision-making process, the inadequate documentation and the continued inability of NSPI to hire a senior fuel procurement manager with international coal market and coal procurement expertise.
>
> We have concerns with respect to NSPI's request for blanket approval of its Fuel Procurement Policies and Procedures Manual. First, approval at this time, is premature as NSPI is still on a learning curve in developing its approach to prudent fuel procurement. There remains work to be done, the most significant of which is the retention of a senior fuel procurement manager who will have views on the appropriate contents of NSPI's Manual. Second, one can anticipate that this Manual, like many policies within NSPI, will be a living

> document. It would be inappropriate for the Board to "approve" the Manual as a whole requiring it to be fixed until such time as NSPI or the Board brings it back for further review. We suggest that at this stage the Board may wish to give direction and guidance on the general approach embodied in the Manual, with a reaffirmation that NSPI remains responsible to exercise independent judgment on the implementation of the Manual and as always, its decision-making will be assessed on the standard of prudence.
>
> (Avon, Rebuttal Submission, pp. 1-3)

Province

[41] The Province, in its Closing Submission, noted that NSPI has made considerable efforts towards improving its fuel procurement practices. It referred to the fact that NSPI has significantly revised its Fuel Procurement Policies and Procedures Manual. The Province noted that Liberty also commented on the significant improvements that NSPI made in this area:

> Q. And if I might just interrupt, to be fair you have found that significant improvements have been made in many, if not most, of your recommendations from last time.
>
> A. (Antonuk) Yes, and based on that, and based on more subtle things, attitude, atmosphere, reading the transcripts, I would now say I am optimistic. I don't know if the company saw the light because they're good guys and girls or whether they just felt the pain from the – – and I don't care, I don't think it matters. I've definitely gone from kind of probably no sense of optimism, maybe not pessimism but no sense of optimism, to thinking that "if they get this job filled, I think they're going to get there, and I think they're going to get there quickly." It's – – that's a fuzzy thing and you know, I can't be very analytical about it, I think that's the main – – you know, I like the portfolio but the main thing I think is different from last year is that I do have that sense that they're going to get there now, and they're going to get there at a pace that – – you know, we always want good things to happen sooner, but I think they're going to get there at a pace that's going to work if they can, you know, get over this problem with finding the right person.
>
> (Transcript, November 29, 2005, pp. 2443-2444)

[42] The Province notes that there are two significant areas where improvement is required. The first was alluded to in Liberty expert witness John Antonuk's comments

above, relating to the hiring of a specialist in coal procurement, and the second one relates to the lack of transparency in decision-making. The Province stated:

> Regarding the employment of an experienced specialist in coal procurement matters, NSPI advised that it has retained a recruitment firm to assist it and has courted a few prospects. For various reasons, however, nothing has come of this. While NSPI is continuing with these efforts, it is also looking at other alternatives, such as retaining a company with considerable experience in coal acquisition.
>
> It will be important for NSPI to continue with these efforts and it seems likely that successfully completing this task will be one of the things that is necessary in order for NSPI to take its fuel procurement practices to the next level. This seems to be a key ingredient according to the portion of evidence from the Liberty fuel panel set out above.
>
> Given the difficulty it is having filling this necessary position at this point in time, NSPI should continue to build up internal expertise. It should also actively seek secondment opportunities or other training. When it deals with its fuel consultants, and once it does hire its specialist, NSPI should ensure that there are appropriate knowledge transfer and succession planning measures in place. This appears to be NSPI's intention.
>
> The lack of transparency in NSPI's fuel purchase decisions is troublesome. NSPI's response to Liberty IR-20 provided copious amounts of documentation regarding various RFP processes undertaken by NSPI to procure fuel. More recently, the documentation involved with these processes has included evaluations done by Ms. Medine, although it would appear that sometimes these evaluations are in draft form and not completed until after Fuel Strategy Table meetings. The most significant concerns that were expressed during the hearing seem to centre around the lack of independent NSPI analysis on procurement decisions and the absence of detailed documentation relating to Fuel Strategy Table meetings and decisions. Instead, what appears is simply a Record of Decision, that simply notes the decision points that have been made without elaboration or justification.
>
> Dr. Rashke [sic] described NSPI's decision-making process as "totally obscure". He characterized the fuel strategy table as a "black box". ...
>
> . . .
>
> Other consultants share these concerns. Mr. Marston described the minutes of Fuel Strategy Table Meetings as "sparse at best". In its prefiled evidence, Liberty also expressed concern about the lack of documentation surrounding NSPI's decision-making processes:
>
> **Q. What documentation formed the basis for this evaluation?**
>
> A. Liberty IR-20 asked a number of questions related to NSPI's fuel and fuel transportation procurement. Included were questions relating to the RFP, vendor lists, vendor responses, NSPI analysis and evaluations, recommendations to management, evidence of proper management review and approval, copies of agreements, and delivery-tracking information necessary to confirm contract

compliance. Our experience in examining many such files at other utilities led us to anticipate that the responses would provide substantial insight into the adequacy of NSPI's decision-making processes.

Q. Did NSPI provide the requested information?

A. Partly.

Q. What information was not provided?

A. NSPI provided the information in five large, three-ring binders. In no case was the requested delivery tracking information provided. In many cases, it was not evident that the proper level of management had reviewed and approved the evaluations and recommendations made by NSPI staff or EVA. In most cases, the files did not contain evaluations and recommendations made by NSPI staff. Instead, it appears that NSPI relied on the evaluations and recommendations of EVA. It was therefore not possible to assess the nature and quality of the analysis and evaluation skills of NSPI staff.

Liberty went on to note that the condition of the information that was provided by NSPI "did not measure up to what Liberty is accustomed to seeing in the equivalent files of utilities that have sufficiently organized contract administration systems". In addition to the foregoing, Liberty also expressed a concern that NSPI's hedging policies and procedures were not sufficiently detailed in its Fuel Procurement Policies and Procedures Manual.

The Province was pleased to note that, in its Rebuttal Evidence, NSPI has undertaken to continue its efforts to revise and develop its formal policies and procedures manual, and in particular, its offer to work with Liberty or alone as the Board sees fit to further refine its hedging policies and procedures, and to provide whatever procurement documentation the Board determines is appropriate. This issue requires follow-up, but NSPI seems determined to address the concerns that have been raised.

(Province ,**Confidential** Closing Submission, pp. 11-14)

3.2.4 Findings

[43] The Board has carefully reviewed the evidence pertaining to NSPI's fuel procurement procedures and the Fuel Procurement Policies and Procedures Manual. The Board notes that Liberty stated in its Direct Evidence that NSPI has made significant and positive changes to its fuel portfolio strategy. Liberty indicated that the new strategy "... is

reasonable, and responds well to Liberty's recommendations in the prior case, ... and includes an appropriately defined mix of long-term, mid-term, and short-term fuel contracts."[11]

[44] The Board recognizes the effort expended by NSPI in implementing many improvements in its fuel procurement procedures, and in the Manual, in the relatively short period of time which has elapsed since the Board's March 31, 2005 decision. The Board is pleased with the dedication shown by NSPI towards improving its procedures in this very important area of NSPI's operations. The Board also notes that there appears to be general acceptance by the intervenors that NSPI has made significant improvements in the fuel procurement area.

[45] However, Liberty also observes that while NSPI had satisfactorily dealt with many of the specific deficiencies in fuel procurement procedures, which Liberty commented on in the last rate case, a number of deficiencies still remain, including those set out in paragraph 34 above.

[46] Liberty, during questioning by the Board, stated that while the new Procedures Manual goes some distance in addressing Liberty's concerns, it does not fully resolve them. Liberty stated:

> We'd like to see the procedures better, we'd like to see the controls tighter, but we'd also and, I think more urgently, like to see the person put in place and ... if it's the right kind of person, we expect he or she is going to say "We need to tighten up these procedures. We need to have more transparency with how we make our decisions on specific procurement."
>
> (Transcript, November 29, 2005, p. 2416)

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[11]Exhibit N-97, pp. 30 and 35

[47] The Board notes that SEB, in its Final Confidential Fuel Related Argument, has recommended against approving the Manual at this time. One of the reasons advanced by SEB for not approving the Manual now is that "... NSPI has yet to hire the high level in-house expertise which the Board ordered in its 2005 rate decision, whoever may eventually fill that role has had no input into the Manual or the Strategy contained in the Manual."[12]

[48] Avon, in its Rebuttal Submission, also argued against providing blanket approval of the Manual at this time. Avon states that:

> ... approval at this time is premature as NSPI is still on a learning curve in developing its approach to prudent fuel procurement. There remains work to be done, the most significant of which is the retention of a senior fuel procurement manager who will have views on the appropriate contents of NSPI's Manual ... It would be inappropriate for the Board to "approve" the Manual as a whole requiring it to be fixed until such time as NSPI or the Board brings it back for further review. We suggest that at this stage the Board may wish to give general direction and guidance on the general approach embodied in the Manual, with a reaffirmation that NSPI remains responsible to exercise independent judgment on the implementation of the Manual and as always, its decision-making will be assessed on the standard of prudence.
>
> (Avon, Redacted Rebuttal Submission, pp. 2-3)

[49] NSPI has requested that the Board approve its Fuel Procurement Policies and Procedures Manual, and confirm that the strategy is being appropriately implemented. While the Board is in general agreement with the Fuel Portfolio Strategy set out in Section 1.2 of the Manual, the Board is not prepared to approve the Manual at this time, nor is it able to confirm that the strategy is being appropriately implemented. The Board has concerns about the significant deficiencies noted and commented on by Liberty and other

[12] SEB, **Confidential** Fuel Related Argument, p. 56

intervenors in this hearing. These deficiencies include a lack of managerial approvals of material fuel purchases, including coal, petcoke, and heavy fuel oil, a lack of adequate evaluations by NSPI staff of various solicitations, a lack of appropriate Fuel Strategy Table documentation surrounding its approval of purchases, a lack of adequate procedures surrounding the procurement of purchased power, and inadequate procedures surrounding the hedging function. Further, in the light of the lack of appropriate approvals, the Board expects that there will be a thorough review of the existing approval protocols set out in the Manual with a view to tightening them up considerably. There may be other aspects of the Manual which need to be strengthened. The Board agrees with Avon that more work is required on the Manual, and that the new fuel procurement manager may suggest significant refinements which ought to be made to the Manual.

[50] The Board is pleased that NSPI, in its Redacted Rebuttal Evidence, has committed to working with Liberty to further refine and improve its hedging policies and procedures, and to provide whatever procurement documentation the Board recommends.

[51] The Board directs that NSPI implement, as soon as possible, all the recommendations by Liberty set out in this decision, and that NSPI file a report by August 31, 2006, outlining the status of the recommendations which were implemented, and those recommendations, if any, which were not implemented. The Board further directs that NSPI liaise with Liberty in the implementation of these recommendations, which are set out in section 3.0 above. The Board notes that there are other directives issued to NSPI by

the Board with respect to the work performed by Liberty, and these directives are found elsewhere in this decision.

[52] In the meantime, notwithstanding that the Manual is not finalized and has not received approval, and the Board has not approved the Fuel Portfolio Strategy, NSPI must proceed with the implementation of its proposed fuel strategy. The Board expects NSPI to use its judgment both with respect to the changes it proposes to the Manual, and with respect to the implementation of the fuel strategy.

[53] In its March 31, 2005 decision, the Board directed NSPI to engage a fuel procurement expert with respect to coal acquisition. This has not occurred. While the Board understands that NSPI has been diligently working to identify and employ such an individual, the Board wishes to convey to NSPI its concern over the lack of progress in this very significant area of NSPI's operations. The proposed expenditure for coal in the 2006 test year, as contained in Appendix A of Exhibit N-2, is $295.4 million, which is by far the largest of any other proposed expenditure for the 2006 test year. It is absolutely critical that NSPI obtain the necessary sophisticated knowledge in coal procurement procedures.

[54] The Board notes that NSPI has been using the services of EVA, on a temporary basis, pending acquisition of the coal expert. While EVA appears to be highly regarded in the international coal community, this is only a short-term measure, and it does not, by itself, ensure the acquisition of the necessary knowledge and skills by NSPI staff.

[55] Accordingly, the Board directs NSPI to continue expeditiously with its efforts to obtain a solid fuel expert. Failing that, NSPI is directed to consider and evaluate other

options which would permit it to acquire the necessary skills to enable it to acquire coal on a competitive basis in the international market. The Board notes that during the hearing other options were suggested. Avon, for example, suggested in its Closing Submission, that consideration could be given to the secondment of an NSPI individual to another organization to acquire the necessary expertise. NSPI is directed to file a quarterly status report with the Board concerning this matter, commencing April 30, 2006. Further, the Board directs that NSPI liaise with Liberty with respect to its progress in finalizing this matter.

3.3 Carryover of Imprudency

3.3.1 Overview

[56] In its rate decision dated March 31, 2005, the Board adopted the standard for determining prudency as defined by the Illinois Commerce Commission:

> ... prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made....Hindsight is not applied in assessing prudence....A utility's decision is prudent if it was within the range of decisions reasonable persons might have made. ... The prudence standard recognizes that reasonable persons can have honest differences of opinion without one or the other necessarily being imprudent.
>
> (Board Decision, March 31, 2005, p. 43)

[57] In the same decision, the Board made the following comments in finding that NSPI's imprudence in its fuel procurement should be set at $18 million for the 2005 test year:

> The Board has carefully considered the evidence heard with respect to NSPI's fuel procurement strategy and actual practices. There is no question that, in the 2002 rate

decision, the Board stopped short of finding NSPI's fuel procurement to be imprudent. The Board understood that with the closure of Devco, and the end of the majority of NSPI's coal supply coming from domestic sources, NSPI had to begin purchasing much of its fuel supply in the international market. The Board believed that NSPI, at that time, was relatively inexperienced in international coal markets and that the Company should be provided with a fair opportunity to make the changes necessary, in both its organizational structure and in fuel procurement practices, to address this important change in its coal supply procurement.

. . .

The Board has carefully reviewed NSPI's defense of its coal procurement strategy since 2002. As NSPI points out, it hired Ms. Medine as an expert in this area; it developed a Fuel Procurement and Procedures Manual which was completed in July of 2004; and it has complied with the Board's 2002 directives to return the coal procurement function to NSPI from Emera. NSPI asserts that it has taken reasonable and necessary steps to improve fuel procurement. According to NSPI, the fact that it currently has no long-term imported coal supply contracts does not fairly represent its revised procurement strategy. As NSPI explains it, during the period of time in question, mid or long-term coal supply contracts were inadvisable, either because of limited interest on the part of suppliers or unduly high prices.

The Board acknowledges that certain of NSPI's fuel procurement processes in 2002 have changed considerably since that time. In 2002, NSPI was relatively inexperienced in terms of importing coal. The Board's findings as to whether NSPI's coal procurement practices in 2002 were imprudent were based on whether the strategy and practices used by NSPI were reasonable and prudent under the circumstances. As noted earlier, at that time, the Board did not find NSPI's coal procurement to be imprudent as it believed NSPI should be given a reasonable opportunity to react to the fairly abrupt end to its reliance on domestic coal supply. This "opportunity" should have involved NSPI quickly acquiring the necessary in-house expertise for imported coal purchasing and expediently revising its purchasing practices to reflect the new reality of the international coal market supply.

It is clear that NSPI took several important steps toward this goal. In early 2003, NSPI engaged Ms. Medine as an external coal consultant and began to develop a Fuel Procurement and Procedures Manual. Ms. Medine's advice regarding the need to have a mixed balance of short, mid and long-term coal supply did not change since her 2002 analysis. Her evidence at this hearing is consistent with her earlier advice. What she could not confirm was whether NSPI had acted quickly and effectively enough to actually implement recommended and necessary improvements in its fuel procurement activity.

. . .

The Board has reviewed the case law cited by the intervenors and NSPI on the question of the acceptable legal standard for a finding of imprudency. As SEB notes, **s. 45(2)** of the **Act** identifies that expenses which the Board may allow a utility to charge must be "... reasonable and prudent and properly chargeable ...". The Board agrees with Avon and SEB that, while expenses are generally presumed to be prudent, when questions are raised with respect to prudency, the burden falls to the utility to satisfy the regulator that its actions were prudent and reasonable.

While the Board recognizes that the definition of imprudence varies somewhat among the jurisdictions cited, there are several fundamental principles which are common. These include:

- Were the utility's decisions reasonable in the context of information which was known (or should have been known) at the time?
- Did the utility act in a reasonable manner and use a reasonable standard of care in its decision-making process?
- The imprudency test should relate to the circumstances at the time in question and not to hindsight.

While several cases were cited on this issue by the parties, NSPI referred in particular to a decision of the Illinois Commerce Commission noted earlier. Following a review of the cases, the Board finds that the definition of imprudence as set out by the Illinois Commerce Commision [sic] is a reasonable test to be applied in Nova Scotia.

Accordingly, the Board has focused on NSPI's performance with respect to fuel procurement on the basis of the circumstances confronting NSPI in late 2002 and 2003. In the context of that test, the Board believes the circumstances at the time are reflected in the 2002 hearing and decision. NSPI faced a significant change in its coal supply. It lacked high-level in-house expertise in the international coal market. It defended allegations of imprudence in coal procurement in 2002 and, while the Board did not make a finding of imprudence, it categorized NSPI's coal procurement as "... lacking in sophistication ..." and "... sufficiently lax so as to undermine NSPI's ability to ensure ... that coal was obtained at the lowest possible price...".[13] In terms of the process for decision-making used since 2002, it has been criticized by Liberty witnesses as lacking in efficiency and accountability. NSPI does not appear to have quickly retained high-level in-house expertise in the international coal market. It is compelling that all of the fuel experts, including Ms. Medine, confirmed that coal prices declined in late 2002 through to mid-to-late 2003. NSPI did not obtain a single long-term coal supply contract during this time.

The issue, in the Board's opinion, is not NSPI's stated intention to improve its practices but the timeliness and effectiveness with which actual implementation of the new approach was achieved. **NSPI, in the Board's view, failed to address its imported coal procurement problems quickly or efficiently enough to adequately protect itself or its ratepayers. Had it done so expeditiously following the 2002 rate hearing, the Board is satisfied that, based on the evidence at this hearing, it was possible for NSPI to create a balanced portfolio of short, mid-term and long-term imported coal at reasonable prices**. Instead, NSPI appears to have slowly implemented the necessary changes to its procurement practices. It remains unclear to the Board whether the corporate philosophy actually changed, and whether the procedures and practices recommended by Ms. Medine are yet fully implemented, particularly with respect to the need for long-term coal supply contracts which exceed terms of twenty-four months.

There is no question that, following the directives issued in the Board's 2002 decision, NSPI had a number of changes to be implemented concerning fuel procurement. It is possible that, in its effort to comply with other Board directives, the necessary changes to its procurement strategy were not dealt with as urgently as should have been the case. However, the practical reality of the need for many of the changes ordered in the 2002 decision was that NSPI had inappropriately transferred core utility functions to Emera without the approval of the Board. To the extent that compliance with the Board's 2002 directives may have had an impact on the alacrity with which NSPI implemented fuel procurement

[13] Board 2002 Rate Decision, October 23, 2002, pp. 27-28

process changes in late 2002 and early 2003, any delay in this regard is attributable to the decisions made by the Utility and Emera. Any financial impact as a result of delay in implementing these changes, specifically with respect to the higher cost of imported coal in 2005, should not be borne by ratepayers.

NSPI now faces a spot market for coal supply that has spiked. Consequently, NSPI and its ratepayers are confronted with higher than necessary fuel costs. The Board finds that NSPI has been imprudent in its fuel procurement practice and, accordingly, it is not fair or reasonable to permit the total of these costs to be passed on to ratepayers. The Board wishes to make it clear that, in its view, this is not a reflection on the integrity or intentions of individuals, particularly those who were part of NSPI's fuel decision-making process. It does, however, reflect a corporate philosophy which did not change with the urgency and purpose required in the circumstances. NSPI, as a result of its management decisions, now faces changing and higher market prices. It will pay higher coal prices because it is almost completely subject to the vagaries of the short-term market for imported coal.

While the Board finds that NSPI has been imprudent in its fuel procurement practice, it does not believe that the approximately $30 million reduction, which was suggested by a number of the parties, is an appropriate amount.

The primary reason the Board does not agree with the suggested $30 million reduction is the relatively limited period of time during which coal prices declined. Even if NSPI had acted as quickly as it should have to change its procurement strategy and build a balanced portfolio of short, mid and long-term contracts, it had, at best, several months to do so. Considering that part of this time would be required to implement the necessary changes, NSPI had a relatively short period of time to take advantage of the decline in imported coal prices.

The Board believes that an $18 million reduction in fuel costs, rather than $30 million, strikes a reasonable balance on this issue... [Emphasis added]

(Board Decision, March 31, 2005, pp. 46-49)

[58] Liberty and many of the intervenors during the current hearing contend that the consequences of NSPI's imprudence extend to the 2006 test year.

3.3.2 Submissions - NSPI

[59] In its Rebuttal Evidence, NSPI set out its views concerning the allegations of imprudence made against it by a number of the consultants in their pre-filed evidence.

[60] NSPI indicated that the evidence of the intervenors and Liberty should have considered the high and volatile world prices ... "in light of the expeditious and transparent manner in which the Company has responded to Board and customer concerns, including adopting a detailed fuel supply portfolio strategy."[14]

[61] NSPI quoted the following from Liberty's Direct Evidence:

> NSPI has established an appropriate fuel supply portfolio strategy, and has taken substantial efforts in building a portfolio that corresponds to it. The short time since the decision in the prior case addressing assembly of this new portfolio makes understandable that the portfolio is not yet fully assembled. NSPI has stated that it intends to complete assembly of the desired portfolio in approximately 24 months; Liberty feels that every effort should be made to accomplish this objective.
>
> (Exhibit N-97, p. 32)

[62] NSPI stated that three issues dominated the fuel-related evidence presented by the intervenors in this case, being NSPI's forecast which it used to estimate the price of uncommitted tonnages, its long-term commitments, and the continuation of the 2005 disallowance concerning the imprudence factor.[15]

[63] NSPI noted that several of the consultants engaged in the current hearing were of the view that there should be a continuation of the $18 million imprudence finding of the 2005 rate case, with the result that the test year fuel costs should be reduced by $18 million. NSPI pointed out that "... there is a misconception that the Company was penalized by $18 million. In fact, NSPI was harmed by almost three times that amount." NSPI reasoned that it had requested a fuel adjustment mechanism, which the Board

[14]Exhibit N-153, p. 6

[15]Exhibit N-153, pp. 9-10

refused, and NSPI estimates that "... it will experience a shortfall of approximately $50 million in comparison to actual fuel costs, only $18 million of which the Board found to be imprudent."[16]

[64] NSPI also stated in its Rebuttal Evidence that the Board did not specify how it calculated the $18 million imprudence disallowance in the 2005 rate case, and suggested that, in EVA's experience, this was not the norm for regulatory bodies.

[65] NSPI's Rebuttal Evidence went on to state:

> While the Board did not share how it derived the disallowance, the Board was quite clear in its opinion that it did not find NSPI to be imprudent for its failure to enter into contracts in 2002. Paragraph 82 of its decision states:
>
>> The Board acknowledges that certain of NSPI's fuel procurement processes in 2002 have changed considerably since that time. In 2002, NSPI was relatively inexperienced in terms of importing coal. The Board's findings as to whether NSPI's coal procurement practices in 2002 were imprudent were based on whether the strategy and practices used by NSPI were reasonable and prudent under the circumstances. As noted earlier, at that time, **the Board did not find NPSI's coal procurement to be imprudent as it believed NSPI should be given a reasonable opportunity to react to the fairly abrupt end to its reliance on domestic coal supply.** This "opportunity" should have involved NSPI quickly acquiring the necessary in-house expertise for imported coal purchasing and expediently revising its purchasing practices to reflect the new reality of the international coal market supply. [Emphasis added in original]
>
> In paragraph 96, the Board goes on to state:
>
>> The primary reason the Board does not agree with the suggested $30 million reduction is the relatively **limited period of time** during which coal prices declined. Even if NSPI had acted as quickly as it should have to change its procurement strategy and build a balanced portfolio of short, mid and long-term contracts, it had, at best several months to do so. Considering that part of this time would be required to implement the necessary changes, **NSPI had a relatively short period of time to take advantage of the decline in imported coal prices.** [Emphasis added in original]

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[16]Exhibit N-153, p. 18

> Based upon these findings, EVA estimates that the period of imprudence to be perhaps February through July of 2003 as shown below. EVA notes that during this period, NSPI purchased all of its 2004 requirements, ahead of schedule and at an enormous cost savings to NSPI ratepayers.
>
> (Exhibit N-153, pp. 19-20)

[66] NSPI notes that Colin V. Gubbins, of the McCloskey Group; Nancy Brockway, of NBrockway & Assoc., a former US utility regulator and consumer advocate; Dr. Raschke and Liberty all concluded that the 2005 disallowance should be continued into the 2006 test year and, in some cases, be higher than the 2005 disallowance.

[67] NSPI continued:

> Those parties recommending a continued or escalating adjustment all suggest that the Board found NSPI's failure to commit to multi-year contract tonnages in 2002 and 2003 to be imprudent. While the Board is the ultimate arbiter of its finding, EVA found no evidence in the Board decision for that to be the case. In fact, as noted above, EVA finds [the] opposite to be true, i.e. the Board did not find NSPI was imprudent for failing to enter into multi-year agreement in 2002 and therefore any lingering impacts from such failure are not relevant to the current Application.
>
> The methodologies employed by the three consultants making this recommendation vary.
>
> (Exhibit N-153, pp. 20-21)

[68] During cross-examination by Board Counsel, Emily Medine, a principal in the firm of Energy Ventures Analysis ("EVA"), and NSPI's fuel expert, stated that she disagreed with the opinion of those experts who say there is a continuing adverse impact on 2006 results due to the imprudence of NSPI in not securing any long-term contracts for coal in late 2002 and 2003. Ms. Medine cited a number of reasons why she disagreed with the opinions of the other experts:

- Ms. Medine stated that she was not sure how the $18 million was calculated in 2005:

> ...my experience in imprudence findings is that there's generally a calculation and, therefore, we can look at the calculation and see whether it's applicable to future years. My sense was that the disallowance was sort of not specifically tied to an event but to general concerns, and I think the company heard that and has responded. So I don't see it tied to a specific event....
>
> (Transcript, November 28, 2005, p. 2194)

- Ms. Medine stated that with respect to the contracts, when a calculation is done "... you need to have some assumptions, and I don't know what assumptions to use in figuring out whether to continue to go forward or not."

- In addition, Ms. Medine explained that the way she read the 2005 decision, there was no particular finding of imprudence in 2002:

> ... so using foregone opportunities for 2002 to calculate a new number did not seem appropriate to me. ... I didn't find any particular activity in 2002 that the Board found to be imprudent, so I have a hard time understanding how you go back to 2002 and look at foregone opportunities, which would have been a contract that the company could have entered, and calculating a number related to that....
>
> (Transcript, November 28, 2005, pp. 2194-2195)

[69] The following exchange between Board Counsel and Ms. Medine is instructive:

> Q. And I'm not asking you to agree with the calculations made by any of those experts. My question to you really was more whether there is anything in your opinion which would lead to the conclusion that while contract supply for 2005 was available to NSPI in 2002 or 2003 that such supply was not available for 2006.
>
> A. The best evidence is what offers were available to the company, and as I said, the only offer in 2002 that had tonnage going through 2006 was the **[confidential]** offer and that was a relatively small tonnage in 2006.
>
> Q. And that was the one used by Dr. Raschke?

A. Dr. Raschke in his evidence just did a calculation. It was only in his opening statement that he then reverted his evidence to a recommendation, but certainly in his evidence itself it was never a recommendation of a disallowance, he just did a calculation.

Q. Is it your evidence that if NSPI had, I guess, called for RFPs for multi-year contracts in 2002 and 2003, proper ones, that they would not have been able to secure supply for 2006?

A. We're simply moving into the world of hypothetical, which in my experience isn't a basis for disallowance. I mean, maybe, if, would have, could have, should have. I don't know the answer to it. I know that when we went out for multi-year we got some respondents that did give for three years, some that gave for one year, some that gave for two years. If you go back and force the market to respond to terms that you want, you know, in theory you should get at a number a bid, but we have no idea how much of a premium somebody would charge the company in this hypothetical world where we would have insisted that we go out and buy for five years or whatever number you'd like to come up with....

Q. What is the difference between 2006 -- and this is what I want you to speak to -- the difference in that respect between 2006 and 2005?

A. Well, as I said, I can't speak to what happened in 2005 because I don't understand how the number was derived. I think in 2006 we are three or four years out from 2002 and we still could have done a multi-year agreement and the agreement would have expired by 2006. I think we're beyond any period of potential imprudence related to a decision or non-decision in 2002.

(Transcript, November 28, 2005, pp. 2196-2199)

[70] In its Reply to the Closing Argument, NSPI stated that the Board must decide whether the imprudence assessed by the Board in its 2005 decision continues to cause damage in 2006, and if so, what is the extent of the damage:

... It is the submission of NSPI that, on the evidence, no damage continues into 2006. NSPI urges the Board to search carefully for the contract opportunity that was not accessed by the Company and to search carefully for the evidence that can be used to calculate the alleged ongoing loss. NSPI submits there is no such evidence. As such, this cannot be a mechanism to reduce an otherwise justified increase in cost recovery.

It is simply not acceptable, in light of the general principles of ratemaking outlined above, to accept speculation, unproven assumptions, inferences or ‘leaps’ as a basis to disallow millions of dollars of revenue to the Company.

(NSPI, Redacted Reply to Closing Argument, p. 8)

3.3.3 Submissions - Intervenors and Board Counsel Witnesses

SEB

[71] In his opening statement, Colin Gubbins, an expert witness appearing on behalf of SEB, stated that past imprudence in NSPI's purchasing strategy has forced NSPI into buying coal at a time when the market for coal has been overheated. It is Mr. Gubbins' view that NSPI's ratepayers should not have to pay for this imprudence.

[72] Mr. Gubbins stated that, had NSPI put in place long-term contracts in 2002 and 2003, it could have saved $45.98 million in 2006. According to Mr. Gubbins, "...The main reason for this disparity is the significant gap that exists between the prices available in 2003 and the estimates provided by Hill and Associates."[17]

[73] Richard Marston, of Marston & Marston Inc., also appearing on behalf of SEB, in his Direct Evidence, stated that in implementing a strategy of staying close to the market, "...NSPI declined to enter into reasonably priced long-term coal agreements in 2002 and 2003 that would have removed significant fuel cost risk through at least 2006".[18]

[74] SEB, in its Final Confidential Fuel Related Argument, stated that "... Each of Mr. Gubbins, Mr. Marston, the Liberty Group and Dr. Raschke have indicated that the failure of NSPI 'to take advantage of the decline in imported coal prices' (2005 rate decision, para. 96) has had a continuing impact for NSPI's 2006 forecast fuel costs...."[19]

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[17]Exhibit N-179, p. 2

[18]Exhibit N-90, pp. 6-7

[19]SEB, Final **Confidential** Fuel Related Argument, p. 13

[75] SEB indicated that Mr. Gubbins has calculated the continuing impact of the prior imprudent behaviour to be $30.4 million with respect to the 2006 test year fuel costs. SEB stated that "... As Mr. Gubbins specifically noted, NSPI's failure to enter into longer term contracts in late 2002/early 2003 has an even more significant impact in 2006 than in 2005, due to the fact that NPSI [sic] has had to purchase coal at an even higher price to cover its 2006 commitments than its 2005 commitments."[20]

[76] SEB took issue with NSPI's comments in its Closing Argument that the Board "... was quite clear it did not find NSPI to be imprudent for any failure to enter into long-term contracts in 2002." It is SEB's view that:

> ... NSPI's interpretation of the 2005 Decision appears strained at best. Because of the clear impact of the failure to have entered into a term arrangement in 2002/2003, NSPI is struggling to find an interpretation that would suggest their failure to act in the past has no impact on the present. The record is clear that this is simply not correct.
>
> (SEB **Confidential** Fuel Related Rebuttal Argument, p. 10)

[77] SEB also took issue with NSPI's assertion that the actual fuel disallowance in 2005 was much larger than the $18 million because the Board did not approve NSPI's proposal for the fuel adjustment mechanism. According to SEB, the disallowance was $18 million, and the Board "... did not approve a fuel adjustment mechanism because it did not feel it was appropriate for NSPI at that time...."[21]

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[20]SEB, Final **Confidential** Fuel Related Argument, p. 15

[21]SEB, Final **Confidential** Fuel Related Rebuttal Argument, p. 11

Avon

[78] In its Closing Submission, Avon stated that the experts and consultants dealing with the fuel issue all believe that the 2006 test year fuel costs are impacted in a negative manner by the past imprudence. Avon summarized the evidence with respect to the past imprudence as follows:

> ... The Liberty Consultants recommended that NSPI's fuel expense for the rate year 2006 should be reduced "because of the continuing harm suffered from past failure to adopt a robust portfolio strategy after its decision not to install scrubbers in 2001 and the resulting missed opportunities to procure long-term fuel supplies in the past at more economical prices."
>
> In its evidence, the Liberty Consulting Group prepared a calculation assuming that in 2002 and onward NSPI had a portfolio strategy in place to secure the 3.5 million tonnes of solid fuel required in 2006 and that conformed to the strategy it is now describing in its current Fuel Procurement Policies and Procedures Manual. During the cross-examination of the Liberty Panel, it was acknowledged that the calculation did not account for the domestic coal contract with Nova Construction. Accordingly, Liberty recalculated its Exhibit LCG3 to summarize the 2006 cost of not having a balanced coal supply portfolio to be $23,300,460.
>
> (Avon, Redacted Closing Submission, p. 3)

[79] In commenting on Dr. Raschke's calculation of an amount for imprudence, Avon stated that his approach was the most conservative, and he calculated imprudence by referring to a "... single specific contract which was available to NSPI but not taken up to fulfill its uncommitted tonnage." Avon quotes from Dr. Raschke, as follows:

> It is also important to remember that in 2006 NSPI's fuel costs still reflect the mistakes it made in the past in its coal purchasing. While in April 2005 it entered into a long-term contract with **[confidential]** while the market was still at or near record highs, in May 6, 2002, it had received a very much lower offer ... which it turned down....
>
> (Avon, Redacted Closing Submission, p. 4)

[80] Dr. Raschke calculated the imprudence to be $8.06 million.

[81] In its Rebuttal Submission, Avon stated that there is unanimity among the experts that there is ample evidence to support an ongoing impact of past imprudence. Avon suggested that Liberty has "... offered a reasonable alternative for calculating the value of the disallowance, being appropriately conservative with respect to pricing and volumes. We submit a disallowance of $23.3 million is appropriate."[22]

Province

[82] The Province, in its Closing Submission, stated that it is necessary to determine if NSPI's failings in late 2002 and early 2003 continue to have cost consequences for the 2006 test year, and if so, to what extent. The Province suggested that:

> When answering these questions, the Board should reflect upon the circumstances that prevailed during late 2002 and early 2003. In the circumstances of this case, the Province does not believe that it is, or was necessary for the Board to have linked a finding of imprudence to the failure of NSPI to enter into a specific contract based on an offer that it had in hand during the relevant time frame. This is because the issue is not only what offers had been made to NSPI at the time, but what offers might have been made had NSPI conducted itself appropriately. To a greater extent, the issue is one of lost opportunity.
>
> . . .
>
> The Province submits that given the Board's past finding that "it was possible for NSPI to create a balanced portfolio of short, mid-term and long-term imported coal at reasonable prices" in late 2002 and early 2003, the benefit of low prices that should have been obtained at that time would still be influencing the budget in 2006....
>
> . . .
>
> Consultants retained by the Board, Stora Enso/Bowater, Avon Valley et al. and the Consumer Advocate all recommended continuing an imprudence disallowance into 2006. Mr. Gubbins noted that because the differential between coal prices in 2002/2003 and 2006 has widened, an imprudence allowance would be higher in 2006 than that awarded by the Board last year.

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[22]Avon, Redacted Rebuttal Submission, p. 10

> He recommended disallowance in 2006 of approximately $46 million. Dr. Raschke uses less volumes in his calculations and recommends a disallowance in 2006 for past imprudence of $8.06 million. Ms. Brockway recommended maintaining the $18 million disallowance into 2006. Liberty recommended a disallowance of $23,300,460.
>
> (Province, **Confidential** Closing Submission, pp. 5-7)

[83] While the Province believes that it is important to recognize that NSPI has made significant improvements in its fuel procurement practices over the past few years, it noted that "... continuing the Board's past imprudence finding into the 2006 rate case would not be a negative commentary on NSPI's more recent fuel procurement activities, but an acknowledgment that its sins of the past are continuing to have cost consequences that should not be borne by ratepayers."[23]

[84] The Province did not suggest a specific amount for an imprudence disallowance, although it expressed the view that the Board ought to continue the imprudence finding into 2006 based upon the assessments by the various consultants. It also agreed with Dr. John Stutz, a regulatory expert and Vice President of the Tellus Institute, and retained by Board Counsel, who stated that "... if the Board determines that it is appropriate to maintain an imprudence allowance into 2006, then it would be beneficial to provide additional guidance on whether the circumstances leading to the Board's past imprudence finding will continue to exert an influence on NSPI's fuel budget beyond 2006. If so, it would be further advisable to define parameters on how the excessive costs in the fuel budget are to be assessed in future years."[24]

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[23]Province, **Confidential** Closing Submission, para. 15

[24]Province, **Confidential** Closing Submission, para. 14

Liberty

[85] In its Direct Evidence, Liberty indicated that NSPI is suffering significant harm from its past failure to adopt a portfolio strategy, and Liberty concluded that, as a result of NSPI's failure to enter into long-term commitments as far back as 2002, 2006 fuel costs will be higher than they otherwise would have been.

[86] Further, it expressed the view that, notwithstanding NSPI's adoption of a portfolio strategy "... The magnitude of that harm has not diminished as much as might have been expected in light of NSPI's change to a portfolio strategy, because 2006 fuel costs now appear to be significantly higher than they did during the last case."[25]

[87] Liberty concluded, in its Direct Evidence, that the fuel expense for the 2006 test year should be reduced by a total of $23,695,740 as a result of NSPI's past failure to adopt a "... robust portfolio strategy ... and the resulting missed opportunities to procure long-term fuel supplies in the past at more economical prices".[26] Subsequently, Liberty reduced their imprudence disallowance to a total of $23,300,460.[27]

Dr. John Stutz

[88] Dr. Stutz was asked by the Board during his testimony whether he thought there should be a finding of imprudence to the extent that 2006 coal was not bought in earlier years when prices were lower. He replied as follows:

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[25]Exhibit N-97, p. 8

[26]Exhibit N-97, p. 11

[27]Undertaking U-64

> ... Let me say to begin that I think it's a very thorny issue, so if you'll permit me, I'm going to address it in three parts. So the first question is, should the coal have been bought earlier and in a fashion which is what we now call a portfolio approach. I believe you answered that question in your last decision. You said basically that should have been done. That was the basis for your finding of imprudence in the last case.
>
> Second question is, is there a continuing harm now from not doing that. And there I think we need you need to rely on experts. Liberty, who have been consistent proponents of the portfolio approach, would tell you there is a continuing harm, and so all I can say is I've listened to all the evidence and I find what they have to say about that point reasonably persuasive, that is, that there is as a qualitative matter a continuing harm.
>
> Now we get to the real thick of it. Do we know how much harm is continuing. And, frankly, I think that's a swamp. I think it requires a fair amount of assumption because you have to imagine what portfolio would have been put in place back at that time in order to assess the harm. Liberty has done that. The company has pointed out and, I would say, it's a fair argument that there were numerous assumptions that underlie that calculation. I think the difficult area for the Board, it will have to exercise its judgement, in my view, is to decide whether and to what extent they can quantify that harm, either as Liberty has done it or by other means, to assess an imprudence penalty.
>
> So I think, just to recap, yes, there was imprudence back then. In my view, the experts have made a case that the harm continues. The key question is, can you get a number. And I think it will ultimately be a matter of your judgment.
>
> (Transcript, December 2, 2005, pp. 3589-3590)

3.3.4 Findings

[89] In its rate decision of March 31, 2005, the Board dealt extensively with the issue of imprudence. It explained why it had ruled, in its 2002 rate decision, that there was no imprudence, and why in the 2005 rate decision, that there was imprudence. Given the significance of these findings with respect to the issue now before the Board, the relevant sections from the 2005 rate decision are set out in section 3.3.1 above.

[90] After considering the record, the Board accepts the evidence of those experts who are of the opinion that there is a continuing harm in 2006 as a result of NSPI's failure to implement a portfolio strategy commencing in 2002. The Board is satisfied that, for the same reasons as the Board found in its decision of March 31, 2005, NSPI had an

opportunity at that time to begin implementing an appropriate fuel procurement strategy. If NSPI had taken advantage of that opportunity as it should have done, it would have been able to obtain coal for 2006 at costs significantly less than those which it now forecasts for the 2006 test year. The additional expense involved should not be borne by the ratepayers because it was imprudently incurred.

[91] The question then becomes, how can these costs be determined or measured? The Board concurs with Dr. Stutz's observation that this is something of a "swamp", which requires the exercise of judgment rather than the pretext of mathematical precision. The Province made a similar point in its Closing Submission:

> When answering these questions, the Board should reflect upon the circumstances that prevailed during late 2002 and early 2003. In the circumstances of this case, the Province does not believe that it is, or was necessary for the Board to have linked a finding of imprudence to the failure of NSPI to enter into a specific contract based on an offer that it had in hand during the relevant time frame. This is because the issue is not only what offers had been made to NSPI at the time, but what offers might have been made had NSPI conducted itself appropriately. To a great extent, the issue is one of lost opportunity.
>
> (Province, Redacted Closing Submissions, para. 7)

[92] The Board notes that the imprudence estimates calculated by the fuel experts range from $8.1 million in the case of Dr. Raschke, to $23.3 million in the case of Liberty, and to $30.4 million in the case of Mr. Gubbins. Each expert has calculated a different figure using different methodologies and assumptions. There is no consensus among them as to the correct amount.

[93] NSPI challenges some of the assumptions made by the experts. The difficulty in determining an appropriate amount for imprudence is the result of NSPI's lack

of activity, during the period commencing in 2002, when the Company should have been taking steps to implement a diversified portfolio of coal contracts, but failed to do so. On this issue, the Board concurs with the comments made by Mr. Antonuk of Liberty during the hearing:

> A. (Antonuk) First of all, I can't - - we didn't do our analysis based on saying the company had a duty to be prudent when the Board told it to be prudent. And the duty for a company to act prudently is an internal responsibility. So I think it would be wrong to suggest that somehow their only obligation is to respond to what you tell them to do and when you tell them to do it, because you don't run the company day to day or even, in most cases, year to year. But here obviously rate cases are pretty frequent. So I guess I have trouble understanding why there is all this focus on when you told them what. From our perspective, we look at what we think reasonable management would have done under the circumstances if they were self-motivated to do the right thing rather than sort of just responding to what you told them. So I've read the transcripts, this is the first time I've seen this one, so that all leaves me cold when I hear "Well when did the Board tell you this? How long should you have had to respond to the Board?" Our whole view of it is what should management have been doing on its own at the time. We believe that the trigger event for starting to look at long-term low-sulphur coal supplies was the analysis in July ---
>
> A. (Spangenberg) '02.
>
> A. (Antonuk) — yeah, and that should have gotten them started. The fact that they didn't get started is why we don't have what Ms. Medine and Mr. Connors were referring to as offers. We weren't buying coal then. It's certainly not our job to come in here and say - or our burden to come in here and say "Well we were trying to buy coal for NSPI and this is what we got offers for." Because that's the level at which you have to have offers. You know, fuel offers are unique to time, unique to quantity, unique to delivery point. So the real issue here is the company, in our opinion, didn't do what it should have done, therefore it didn't have offers. What do we do? We're not going to go and look at what some company in Arizona got offered for coal at that time frame because we'd argue that's irrelevant. What we tried to do is say what's the best information that the company got in response to what it did do.
>
> . . .
>
> And remember, what this all comes down to is not that Liberty failed to solicit coal in 2002, it's that the company did. So the lack of information is certainly not our fault. The lack of information is because they were not doing what they should have been doing. So what we're trying to do is use the best information available to say what would have happened had they done that. And I look at N-216 and I say I think you have to take a pretty darn narrow view of the world to say that the company who

> submitted this was not going to be able to supply in 2006 the very same quantities that they were willing to offer in 2003 through 2005....
>
> (Transcript, November 29, 2005, pp. 2456-2459)

[94] As noted in the evidence quoted above, the difficulty in assigning a reasonable disallowance for imprudence is the result of NSPI's failure to take appropriate action to build a diversified portfolio in a timely manner. In the end, the Board must determine what amount is reasonable in the circumstances.

[95] In reviewing the specific recommendations for an imprudence disallowance, the Board considers that Mr. Gubbins' recommendation is on the high side, and he relied on more aggressive assumptions in his calculations than either of the other two experts. The Board believes that an imprudence disallowance in the mid-range between the amounts recommended by Dr. Raschke and Liberty is just and reasonable in the circumstances. Accordingly, the Board sets the imprudence disallowance for the 2006 test year at $15,700,000.

[96] To avoid any uncertainty going forward, the Board wishes to make it clear that the impact of NSPI's past imprudence for the failings discussed in this decision is now spent and will not extend beyond the 2006 test year. This is because, even if NSPI had entered into a multi-year contract in 2002 and 2003, as the Board considers it should have done, the Board is satisfied that such contract would have likely run its course by the end of 2006.

3.4 Long-Term Contract

3.4.1 Submissions - NSPI

[97] In April of 2005, NSPI entered into a multi-year contract to acquire low sulphur import coal, which NSPI states was in accordance with its portfolio strategy. NSPI's Rebuttal Evidence sets out its position with respect to this contract as follows:

> ... NSPI solicited the market, evaluated the alternative bids, negotiated with a short list of bidders and then selected [the supplier]. According to Liberty, "NSPI properly handled the solicitation, including a sufficient number of qualified potential suppliers, conducting bid evaluations, and making a decision that appears sound from the information that NSPI provided. NSPI procured the least-cost supply offered."
>
> Nevertheless, SEB and Avon's consultants heavily criticized this transaction. Mr. Marston states "Nothing in the 2005 Decision justifies NSPI's decision to enter into a long-term, high priced contract near a well-recognized market peak with indifference to market conditions and expectations."(Page 9 Marston evidence) Mr. Gubbins believes the commitment **[confidential]** ran counter to the evidence he had provided the Board. (Page 4 Gubbins evidence) Dr. Raschke states that "having adopted an appropriate strategy, NSPI has erred in implementing it." (Page 48 Raschke evidence)
>
> This transaction demonstrates very clearly a point NSPI made in its Rebuttal Testimony in the 2005 Application. Experts disagree. Even reasonable experts disagree. The Board's consultant, Liberty, believed that NSPI should immediately enter into long-term contracts as part of a contract portfolio. SEB's and Avon's experts believed that NSPI should have a contract portfolio but should delay entering into long-term agreements until there was a market adjustment. Not surprisingly then, the Liberty consultants applauded NSPI's contract **[confidential]** SEB's and Avon's experts found it imprudent.
>
> While the Board in its opinion did not contain a specific finding on this matter, it was clear to NSPI that the Board believed NSPI should have a contract portfolio and did not disagree with its own staff's consultant, Liberty, that such contracts should be committed to in a timely manner.
>
> NSPI attempted to be responsive to all evidence submitted in the 2005 Application in accordance with its own obligations to procure fuel in a responsible manner as follows:
>
> - NSPI entered into one multi-year contract at the most competitive price at the time the coal was selected with a reputable supplier of high quality coal that provided for the maximum volume optionality such that it could reduce volumes should the market adjustment occur. Further, NSPI believed that this coal provided unique arbitrage opportunities ... The agreement is **[confidential]** not a long-term agreement, which as NSPI's policies and procedures state is desirable for contracts during a high-priced market period.

- NSPI pursued **[confidential]** contracts with suppliers with indexed pricing precisely because of its recognition of the potential market adjustment. The pricing in the agreements was not only to be tied to an index but it would give NSPI the unilateral right to convert to fixed pricing in the event that (1) pricing spiked or (2) pricing fell to very low levels ...

- NSPI expanded its testing program to include tests **[confidential]** such that when the market adjustment occurred it would be prepared to maximize competition by having a larger number of sourcing options.

It is quite telling that the SEB and Avon consultants did not applaud NSPI for its efforts to incorporate their world view into the procurement process by minimizing the multi-year commitment, seeking contracts with indexed pricing, and conducting multiple tests of non-traditional sources.

(Exhibit N-153, pp. 15-18)

[98] In its Closing Argument, NSPI contended that it acted prudently in signing the three-year contract and asserted that its decision to do so must be assessed in the context of the following facts:

- NSPI had been heavily criticized by consultants and intervenors during the rate hearing in November of 2004 for failing to implement a portfolio strategy with multi-year contracts in a timely manner;

- NSPI had issued a request for proposals for low-sulphur coal in January 2005 and concluded that the multi-year offers were not attractive in the context of softening world coal prices. Another RFP was issued for April 2005 and the bid prices then received were lower than the January 2005 bid prices;

- Coal prices fallen substantially from their peak in July 2004, but remained volatile;

- Hill & Associates issued its price forecast in March 2005 that predicted continued high prices through 2006;

- NSPI had advice from its fuel consultant, Emily Medine of EVA, that recommended NSPI purchase this coal because it had the lowest evaluated costs of the eight coal bids and **[confidential]** is the premium product in the Atlantic market which may lend itself to arbitrage opportunities;

- The **[confidential]** contract was a medium term contract consistent with NSPI's policies and procedures to use medium term contracts rather than long term contracts during higher priced periods;

- The **[confidential]** contract at minimum contract levels accounted for only about 10% of NSPI's solid fuel requirements on a tonnage basis in 2006 and 2007 and five percent in 2008;

- The **[confidential]** contract was only one element of the portfolio being negotiated at that time. NSPI also initiated contract negotiations with two other suppliers for multi-year agreements based upon index pricing, thereby providing diversification of pricing mechanisms for the contract commitments in the portfolio consistent with NSPI's portfolio strategy; and

- As a result of the competitive bids for **[confidential]** at the time, NSPI decided to undertake testing programs for these coals to determine if they could be purchased in the future (consistent with NSPI's policy and procedures regarding previously untested coals).

(NSPI, Redacted Closing Argument, pp. 13-15)

[99] NSPI is of the view that it ought not to be found imprudent as a result of its April 2005 contract for the purchase of low-sulphur coal. In support of its position, it pointed out that both Dr. Raschke and Liberty were of the view that the contract was not imprudent.

3.4.2 Submissions - Intervenors and Liberty

SEB

[100] SEB, in its Final Confidential Fuel Related Argument, maintained that the overriding concern is that NSPI appears to have entered into the April 2005 long-term contract with little, if any, consideration of the market.

[101] SEB expressed the view that, based on Ms. Medine's evidence, NSPI felt the "need" to quickly enter into a multi-year agreement, and that this "need" impacted NSPI's evaluation of the bids received in April 2005:

The first paragraph under the heading "Bid Evaluation" in Exhibit N-169 is very telling:

> Under normal circumstances a term bid is evaluated both against its competition as well as the expectation for market prices. This is not a normal circumstances given NSPI's commitment to develop its portfolio and **the need to enter into a term agreement at this time**. Therefore, a "traditional" contract evaluation is not performed in which the contract alternatives are compared simply against market [Emphasis added in original]

. . .

Ms. Medine summarized NSPI's position at Transcript, Page 811 as follows:

> So, it had nothing specifically to do with whether the Company was coming back or not ["it" being the implementation of a fuel procurement portfolio] but there was clearly evidence in the proceeding in the summaries — in the submissions that NSPI's customers — and it was confirmed by the Board in its decision in March — wanted more portfolio strategy implemented quickly.

(SEB, Final **Confidential** Fuel Related Argument, p. 24)

[102] SEB referred to a comment by Mr. Gubbins in his Direct Evidence, emphasizing an observation made by him in the 2005 rate case:

> From the standpoint of NSPI's present highly exposed position, long-term contracts should now only be considered after the coal market returns to a more balanced level of supply/demand.
>
> . . .

Mr. Gubbins' testimony, and SEB's position on this matter, could not have been made clearer during the 2005 proceeding or in SEB's argument in that case. Their view was that from the standpoint of NSPI's then existing highly exposed position, long term contracts should only be considered after the coal market had returned to a more balanced level of supply/demand, which was simply not the case in April of 2005. There was no reference anywhere in SEB's argument to NSPI "immediately" or "quickly" entering into a portfolio (Transcript, page 1706)

(SEB, Final **Confidential** Fuel Related Argument, pp. 25-26)

[103] SEB commented that:

In this proceeding, Mr. Gubbins specifically noted:

> A. It's certainly not consistent with the long-term aim of having a portfolio strategy, and I think my point I would always make is you shouldn't be where you are now. Therefore the strategy you've got in place is certainly a long-term strategy, that you've got to take time to get there, and you've got to make sensible purchasing decisions

> in the period to getting there. I mean, you're in a period of very high prices still. In fact, the prices have come off quite considerably. This makes it very important that you don't just rush into a strategy that says you have to have long-term contracts because somebody, you think, has said you've got to have long-term contracts. You've got to go through something which makes sense. You've got to have a sensible coal purchasing programme, and then you move into the long-term strategy that you're talking about when the market conditions are right and when they're stable, when you can see something - - you can actually see what's happening. I think you've pointed out the fact that there's been tremendous uncertainty around the whole time. That is not the time to go into long-term contracts. (Transcript, pages 1267-1268)

(SEB, Final **Confidential** Fuel Related Argument, p. 26)

[104] The following quote from SEB's Final Confidential Fuel Related Argument sets out, in some detail, its views of the contract entered into by NSPI in April, 2005:

> As the foregoing discussion indicates, the record in this proceeding simply does not justify the entering into of the **[confidential]** contract as a prudent decision by NSPI considering the then existing market prices for imported **[confidential]** coal. SEB respectfully submits that the record in this proceeding has clearly demonstrated significant doubt as to the prudence of entering into the **[confidential]** contract, and as explained earlier the burden has shifted to NSPI to demonstrate that this contract was both reasonable and prudent. As described in Appendix A the jurisprudence imposes a clear requirement that NSPI produce evidence of what its decision was based upon, and not only does it bear the burden of proving that its decisions were prudent, but it must also put forward evidence of what activities it undertook to underpin those decisions. SEB submits that NSPI has not demonstrated to the Board through the Hearing process that "ratepayers money [has been] wisely and frugally spent" as the Board required in its October 23, 2002 Decision (see Appendix "A").
>
> SEB respectfully submits that NSPI has failed to discharge is [sic] burden of demonstrating that its contracting decision was prudent, in that it has not provided a record which demonstrates the decision "to be the result of a logical process, guided by a reasonable set of considerations, encompassing relevant information known or which should have been known at the time" (see Appendix A). In fact, the exact opposite is demonstrated by the record. NSPI read the Board's 2005 Decision to mean that it had to move "quickly" to develop a portfolio of contracts. SEB submits that nothing in the Board's 2005 Decision suggests this is the case. In fact, the issue with respect to timing raised by the Board in the 2005 Decision was NSPI's failure to act in a timely fashion in entering into longer term contracts in the late 2002/2003 time period which was the basis for the Board's $18 million disallowance discussed above. The Board was concerned that NSPI had not entered into longer term arrangements at a time when market prices were low; there is no indication in the 2005 Decision that it was suggesting that NSPI should subsequently enter into longer term arrangements when market prices were high.

Furthermore, as noted by Mr. Antonuk's comments earlier in this Submission (Transcript, page 2456), the utility and not the Board is charged with the burden of making reasonable and prudent management decisions.

NSPI appears to have fundamentally misunderstood the Board's findings with respect to the 2005 imprudence disallowance and furthermore, and more importantly, with respect to the **[confidential]** contract, felt that the 2005 Decision somehow mandated that it develop longer term contracts as part of a portfolio strategy notwithstanding market conditions.

This "need" to act "quickly", the lack of an evaluation against market, and little or no supporting documentation from NSPI's management or in-house fuel procurement department, does not provide a basis for NSPI to be able to support a finding of prudence with respect to the entering into of the **[confidential]** contract.

As Mr. Gubbins initially indicated in his Direct Testimony (Ex. N-90) at pages 6 and 7, and in the Spreadsheet attached to his response to NSPI IR-3 (Ex. N-137), the appropriate disallowance to be made on account of the **[confidential]** contract was $5.8 million. His revised spreadsheet incorporating the **[confidential]** calorific correction discussed previously shows a proposed disallowance of $4.1 million.

Mr. Gubbins specifically noted at page 6 of his Direct Evidence (Ex. N-90) as follows:

> In April 2005 NSPI entered into a long term contract to purchase **[confidential]** coal ...
>
> We would question the wisdom of this decision since it goes directly against the advice that we gave in the 2004 hearing. The coal market is cyclical, having peaked in July 2004, but still being at very high levels in April 2005. Since this date prices have declined further in spite of increasing oil prices (see figures 1 and 4), illustrating that coal prices are not entirely linked to overall energy prices but determined by their own dynamics in the market place. Figures 1, 4 and 5 illustrate the cyclicality of coal prices with cycles traditionally 5 to 6 years in duration as we indicated last Fall. Figure 5 shows that there is a close correlation between changes in demand and prices ... The cycles appear to be getting shorter and volatility greater. NSPI therefore entered into a long term contract when, although softening, prices were still high. In our view the prudent course would have been to have waited and continue with a short term purchasing strategy as we indicated last Fall.

The trend line for imported ... coal has continued to be downward since the date of the filing of Mr. Gubbins' evidence.

Interestingly, as noted above, Dr. Raschke although not stating that the contract was imprudent per se, pointed out that the costs to other NSPI ratepayers of the decision to enter into the **[confidential]** contract were "considerable"....

NSPI contends that they find support for their decision in the evidence of the Liberty Group. The Board should note however that NSPI finds favour with Liberty's conclusions when they are in accord with NSPI, but yet does not accept any of Liberty's suggested adjustments when they are not in accord with the utility (Transcript, pages 2001-2003). Furthermore,

> Liberty appears to favour a portfolio approach to contracting and therefore felt it was appropriate for NSPI to commence the development of that portfolio, but they note the fundamental lack of support in the record for NSPI's decision-making as previously noted. It is in fact NSPI's failure to rationally support its decision to enter into the **[confidential]** contract, together with the contract's pricing *vis a vis* market trends for 2006, that support the requirement for a disallowance. SEB submits that the cross examination of the NSPI fuel panel, subsequent to the filing of Liberty's evidence and the examination of Dr. Raschke, further demonstrated the inadequacy and irrationality of the decision-making which surrounded the **[confidential]** contract.
>
> (SEB, Final **Confidential** Fuel Related Argument, pp. 27-30)

AVON

[105] Avon, in its Rebuttal Submission observed that NSPI has made advances in developing and implementing a portfolio strategy; however, whether or not the strategy is being implemented in an appropriate manner is a different consideration than whether a particular coal contract is prudent.

[106] Avon took issue with NSPI's assertion that Dr. Raschke had somehow endorsed the April 2005 contract, or that he was of the opinion that it was reasonable for NSPI to take immediate steps to implement the portfolio strategy. Avon argued that Dr. Raschke had merely pointed out that it appeared NSPI concluded it should act quickly to implement the portfolio strategy; however, according to Avon, Dr. Raschke never agreed that this was a reasonable thing to do.

LIBERTY

[107] In its Direct Evidence, Liberty had this to say about the April 2005 multi-year contract:

A. NSPI's April 2005 solicitations sought **[confidential]** tonnes per year of long-term low-sulfur coal supply through 2008. NSPI recognized this solicitation as its first attempt to add a long-term solid fuel supply contract to its portfolio, in response to the Board's March 2005 decision. NSPI properly handled the solicitation, including a sufficient number of qualified potential suppliers, conducting bid evaluations, and making a decision that appears sound from the information that NSPI provided. NSPI procured the least-cost supply offered. This procurement was the only long-term solid-fuel supply agreement entered during the 2004/2005 period, but NSIP [sic] did make shorter term purchases.

(Exhibit N-97, pp. 30-31)

[108] Liberty stated, during cross-examination, that it believes NSPI acted prudently in entering into the April 2005 contract, and it disagreed with those consultants who were of a contrary view:

Q. And are you aware that some of the consultants on behalf of some of the customers have suggested that the company acted imprudently in entering that **[confidential]** multi-year deal?

A. (Spangenberg) I'm aware of that.

Q. Would you - - is it true that Liberty does not share that view but instead believes that Nova Scotia Power acted prudently in entering the **[confidential]** multi-year agreement?

A. (Spangenberg) Yes.

(Transcript, November 29, 2005, pp. 2365-2366)

3.4.3 Findings

[109] The Board has carefully considered the matter of the April 2005 contract. The importance of having a balanced portfolio strategy for fuel procurement was discussed at length in the last rate hearing. In the 2005 rate decision, the Board commented as follows:

[65] Colin V. Gubbins of the McCloskey Group, Richard Marston of Marston & Marston Inc. and Sharon Hennings of Brubaker and Associates Inc. all gave evidence on behalf of SEB with respect to fuel. Both Mr. Gubbins and Mr. Marston provided their views with respect to world coal markets and NSPI's fuel procurement practices in pre-filed direct evidence and in their testimony at the hearing. Both experts take a similar view of NSPI's procurement strategy. They do not believe it is appropriate. In their opinion, NSPI has not, since 2002, adequately pursued a balanced portfolio of short, mid-term and long-term coal supply contracts and, consequently, customers are not adequately protected against price volatility. They were critical of NSPI's solicitation of the market between 2002 and 2004 for long-term contracts. They noted that coal prices had reached low levels in late 2002 and that Ms. Medine's evidence in the 2002 hearing, which indicated that NSPI should pursue a balanced portfolio of short, mid and long-term contracts, was correct. In their view, NSPI did not act quickly or effectively enough to follow this advice.

[66] Mr. Gubbins and Mr. Marston generally agree that NSPI had a window of opportunity in late 2002 and early 2003 to lock in reasonably priced, long-term coal supply contracts. They indicated that NSPI overlooked this opportunity and, instead, focused on shorter term contracts. As a result, NSPI and its ratepayers are exposed to a sharp increase in coal prices and, had NSPI acted prudently, this price increase could have been reduced. Mr. Marston, in Exhibit N-71, indicated that NSPI relies primarily on market timing in solid fuel purchases, rather than clear guidelines or price objectives. His opinion is that the solid imported fuel costs projected by NSPI for 2005 are "... based on an unreasonable and imprudent fuel procurement strategy and are unreasonably high because of NSPI's over-exposure to short-term and spot contracts." Mr. Gubbins advises that, despite the reference to 24 months as the preferred maximum length of fuel supply contracts noted in NSPI's new manual, long-term contracts are generally understood in the industry to be between three and five years in length.

[67] Dr. Manfred Raschke, of International Strategic Information Services, gave fuel evidence on behalf of Avon. He is also of the view that a balanced portfolio of short, mid-term and long-term coal supply contracts is necessary to avoid high risk exposure to coal price volatility and is essential for a prudent fuel procurement strategy. He indicated that, in his opinion, NSPI does not have a balanced portfolio for coal supply and, as a result, NSPI and its customers are vulnerable to spot markets and price volatility. Dr. Raschke also pointed out that had NSPI moved quickly to adopt a balanced portfolio in late 2002 and early 2003 (which was Ms. Medine's advice during the 2002 rate case) it could have reduced the impact of the high 2005 coal costs it now faces.

[68] Liberty expert witnesses were John Antonuk, Donald T. Spangenberg, Jr., Dennis Kalbarczyk and John B. Adger, Jr. They took a similar view with respect to NSPI's fuel procurement strategy. Mr. Spangenberg indicated that his review of NSPI centred on fuel management, particularly coal. He testified that, in his opinion, NSPI did not use a balanced portfolio approach to secure coal supplies and that NSPI's fuel procurement procedures, as well as the structure of its organization and internal expertise relating to this issue, are inadequate.

(Board Decision, March 31, 2005, pp. 32-34)

[110] In its 2005 rate decision, the Board set out Liberty's recommendations concerning the fuel portfolio strategy:

> Mr. Spangenberg's recommendations are:
>
> 1. NSPI should immediately conduct an overall re-evaluation of its generating system to determine the optimum way of meeting new requirements for control of SO_2 emissions, as well as emissions of other pollutants of concern, from its generating plants. Such re-evaluation should incorporate a long-term view, not just the next several years. The recommended study should consider not only all fuel supply options, but also integration of fuel supply options with capital expenditures for alteration, modification or expansion of its generating units in order to achieve the lowest possible costs for generation of power, consistent with other issues of reliability, environmental concerns and legal issues.
>
> 2. Consistent with item #1 above, NSPI should immediately revise its fuel portfolio strategy to incorporate a balance of both short-term (or spot) and long-term fuel contracts with terms ranging from one up to seven years, with expiration dates not all occurring at the same time.
>
> 3. NSPI should adopt a consistent policy of annual solicitations for long-term coal supply that are accompanied by production quality model runs for at least seven years into the future in order to determine actual fuel requirements. Such model runs should also provide the base for evaluation of proposals received from coal suppliers in order to conduct analysis of variances, such as fuel switching costs to comply with the lower SO_2 emission requirements.
>
> 4. NSPI should revise its coal solicitation process to make it an aggressive one that conveys the image of a utility operating from a position of professionalism and strength. RFP language must be clear and correct, and RFP's must be very clear about the specific fuel supply needs of the future, in terms of tonnes of coal required for each year in the future up to a maximum of seven years. Do not leave tonnages and years of supply at the discretion of fuel suppliers. NSPI must demonstrate it is a professional and serious fuel buyer that knows what it wants, and when it wants it.
>
> (Board Decision, March 31, 2005, p. 36)

[111] The Board concluded that "... The prudency and effectiveness of a balanced portfolio of short, mid-term and long-term coal contracts was unquestionable...."[28]

[112] The Board also stated:

> The issue, in the Board's opinion, is not NSPI's stated intention to improve its practices but the timeliness and effectiveness with which actual implementation of the new approach was achieved. NSPI, in the Board's view, failed to address its imported coal procurement problems quickly or efficiently enough to adequately protect itself or its ratepayers. Had it done so expeditiously following the 2002 rate hearing, the Board is satisfied that, based on the evidence at this hearing, it was possible for NSPI to create a balanced portfolio of short, mid-term and long-term imported coal at reasonable prices. Instead, NSPI appears to have slowly implemented the necessary changes to its procurement practices. It remains unclear to the Board whether the corporate philosophy actually changed, and whether the procedures and practices recommended by Ms. Medine are yet fully implemented, particularly with respect to the need for long-term coal supply contracts which exceed terms of twenty-four months.
>
> (Board Decision, March 31, 2005, pp. 47-48)

[113] There is no question that the message to NSPI from the Board's 2005 rate decision was that a balanced fuel portfolio had to be implemented as soon as possible. The Board stated that the issue was not NSPI's intention to improve its practices, but its timeliness and effectiveness in achieving the new approach. Liberty had specifically stated that NSPI should "... immediately revise its fuel portfolio strategy to incorporate a balance of both short-term and long-term contracts ..."

[114] The Board's decision was issued on March 31, 2005, and NSPI entered into its first multi-year contract in April of 2005. Coal prices had fallen somewhat at the time, and although they were still fairly high, there was no assurance that NSPI could achieve more favourable prices by waiting out the market. Certainly, the forecasts of various

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[28]Board Decision, March 31, 2005, para. 80

experts were no guarantee which way coal prices would trend. The absence of a balanced portfolio left NSPI in a particularly vulnerable position. NSPI acted with dispatch in entering into the contract. One of the advantages of a portfolio approach to coal purchases is that it balances high costs with low costs and does not rely on outguessing the market. The adoption of a balanced portfolio approach will, by its very nature, result in some contracts being entered into during periods of relatively high prices. It would be dangerous, in the Board's view, to undermine a balanced portfolio strategy by insisting that all multi-year coal contracts be entered into only during periods of relatively low prices. The reality is that no one knows, except with the benefit of hindsight, whether prices are going to go up or down at any particular point in time. Otherwise, there would be no need to have a balanced portfolio strategy in the first place.

[115] Accordingly, the Board finds that the April 2005 contract was not an imprudent transaction.

3.5 Affiliate Activity

3.5.1 Submissions - NSPI

[116] In its Rebuttal Evidence, NSPI outlined the nature of the relationship between NSPI and Emera Energy Services (EES), an affiliated company to which NSPI sells its natural gas:

> As in the last rate application Board staff consultants have commented on the contract with Emera Energy Services (EES) for resale of natural gas contracted to NSPI.
>
> This contract has built-in transparency and has been a significant benefit to NSPI customers.

NSPI previously advised the Board that the contract term was being extended so as to not prejudice the gas supply contract arbitration. NSPI has also informed the Board that a reputable third-party will supervise a new solicitation, and participate in the evaluation of bids that come forward during this solicitation.

NSPI disagrees with the characterization that it does not treat gas resales as a core utility function. In competitively identifying a third party to buy and resell its natural gas NSPI structured the arrangement so that it maintained control over the following:

- The amount of gas sold or burned;
- The amount of gas sold monthly or. [sic] Daily;
- Management of the gas cuts from NSPI's supplier;
- The ability to hedge the volume and price of gas.

The contract provides a premium value over the gas market price- -an advantage to NSPI's customers. The contract does not take away from the underlying market value. NSPI has the mechanisms to participate in the value the gas market can provide.

None of the above stated functions is controlled by the affiliate. NSPI, through daily and monthly instructions, directs EES. EES, as bound by the contract, pays NSPI pursuant to the agreed pricing structure which is fully transparent. NSPI still maintains full responsibility for the sale of its natural gas. The contract does not take away NSPI's ability to manage supply cuts, generation requirements, monthly versus daily pricing and with financial hedging.

NSPI decided to enter a term arrangement to sell its natural gas, for exactly the reasons Liberty stated were not considered. As referenced in documentation provided in the last rate application outlining the evaluation of the bids for the resale of natural gas, NSPI was concerned that sophisticated buyers were taking advantage of the fact that NSPI must either sell its gas or burn it. To protect value for customers NSPI needed an arrangement that locked in the value of the market. The RFP and resulting contract did that, securing a premium to an M3 published index in the winter months and no less than market driving other months. In comparison bids from other counterparties offered less value. Given uncertainties with supply and demand the EES contract offered the best price and flexibility.

(Exhibit N-153, pp. 48-49)

[117] NSPI, in its Closing Argument, reiterated that the resale of natural gas has been a significant benefit to NSPI's customers, and that NSPI intends to continue to dispose of its excess natural gas in this manner. It stated that "Now that the arbitration process is complete, NSPI is arranging for a reputable third-party to supervise a new

solicitation, and participate in the evaluation of bids that come forward during this solicitation."[29]

[118] At the hearing, Counsel for NSPI clarified its intent to select a reputable third-party to supervise the new solicitation. James L. Connors, Q.C., Counsel for NSPI, stated that "...The correspondence which has gone to the Board which refers to a third party is a proposal, and the company is now actively pursuing this, to select an independent third party who would administer the RFP process for gas sales next year. So, in other words, what's under way is the picking of an expert independent company who will then be the ones who run the RFP..."[30]

[119] During cross-examination of the NSPI Fuel Panel by David MacDougall, Counsel for SEB, Ralph Tedesco, NSPI's Chief Operating Officer, outlined the process underway for the selection of the independent third party, and he stated that the Company had, after identifying somewhere between 12 and 16 third parties, narrowed the field to two who would be offered the opportunity to administer the solicitation process. Mr. Tedesco also confirmed that EES was not one of the two finalists with respect to the solicitation contract.[31]

[120] In its Closing Argument, NSPI discussed the transparency of the sale of its natural gas, and quoted the evidence of Chris Huskilson, President and Chief Executive Officer of NSPI, as follows:

[29] NSPI, Redacted Closing Argument, p. 93

[30] Transcript, November 29, 2005, p. 2423

[31] Transcript, November 25, 2005, pp. 1993-1994

> Mr. Chair, just for clarification, I would like just a couple of clarifying points on this if you don't mind. First of all, I think it should be clear to the Board that all these transactions are being done at market transparent pricing, so it - - again, that's a very recognizable and transparent way to do business, for sure. The second thing is that any transaction that's done in this light is done such that things like the credit exposure is being transferred between the company, Nova Scotia Power, and the affiliate. So there's a significant credit exposure that Nova Scotia Power doesn't have to bear. And ultimately, that – you know, that is part of – one of the reasons why Nova Scotia Power would want to do this. And just the last point is that when you look at these transactions, they don't actually bear on setting the forward price of electricity or the future test year because all of those things are done based on the way that we look at market forward prices and so on, and any of these transactions only happen after the price of electricity is set.
>
> (NSPI, Redacted Closing Argument, p. 93)

[121] NSPI stated that Liberty has put forth no evidence to show that NSPI's customers experienced any loss of benefit or harm as a result of NSPI's dealings with EES.

> If there were any doubt about the clear benefits that are provided to customers by this particular contract with an NSPI affiliate, Liberty would certainly be presenting a recommendation to reduce the test year revenue requirement accordingly. No such recommendation has been made ... NSPI submits that the contract with its affiliate, EES, is in the best interests of customers.
>
> (NSPI, Redacted Closing Argument, p. 95)

[122] NSPI referred to Undertaking U-84 which provided a summary of the net income accruing to EES as a result of selling the gas which it purchased from NSPI. NSPI pointed out that the summary indicates that the net income arising from such sales is a very small percentage of EES's overall business.[32]

[32]NSPI, Redacted Closing Argument, p. 94

3.5.2 Submissions - Liberty

[123] In its Direct Evidence, Liberty discussed affiliate transactions relating to heavy fuel oil (HFO) and natural gas.

[124] With respect to the acquisition of HFO, Liberty indicated that it found the same type of problems which existed in the solicitation process for coal and petcoke. It stated that:

> ... We reviewed the solicitation that the Company conducted for its 2005 requirements for HFO. We found documentation problems similar to those for coal and petcoke procurement. All eight firms on the original bidders list for the solicitation received the RFP. However, the documentation does not provide any analysis of bids; it contained only a purchase order approval signed by NSPI management. The documentation does not discuss why the award to **[confidential]** constituted the best supply option for NSPI, and there is no management approval documentation providing authority to proceed with the award of business to this supplier.
>
> (Exhibit N-97, pp. 62-63)

[125] Liberty reviewed the HFO transactions between NSPI and Emera Fuels, an affiliated company. It concluded that there were purchases in significant amounts by NSPI from Emera Fuels in both 2004 and early 2005. Liberty also concluded that NSPI sold HFO to Emera Fuels. Liberty stated that:

> The response to Liberty IR-20 gives reason to suspect that these procurements do not follow normal processes with respect to competitive purchases and management approvals. There is, moreover, the question of whether they otherwise took place at arm's-length, considering that they involved an affiliate.
>
> (Exhibit N-97, pp. 64-65)

[126] Liberty expressed concern over these transactions, and suggested that the misgivings which it expressed in the last rate case about affiliate transactions have been

substantiated and broadened as a result of its findings in the present case. Liberty concluded that:

> ... a utility should not buy or sell what it otherwise would not, just because an affiliate happens to have or need the commodity in question...
>
> We can think of no practical way to measure what, if any, affect [sic] affiliate transactions of this type will have on expenses in a future year. We can, however, state that they have the potential, based on what we have observed at other enterprises that permit purchase and sale transactions between utility and non-utility affiliates, to have a significant impact on utility costs.
>
> It is for these reasons that we recommended before and continue to recommend an audit of affiliate transactions and relationships within Emera, as they affect NSPI costs and operations.
>
> (Exhibit N-97, pp. 65-66)

[127] Liberty noted that Emera had recently sold Emera Fuels. Thus, Emera Fuels is no longer directly affiliated with NSPI, and it may be that all transactions between NSPI and Emera Fuels will cease before the commencement of 2006. However, Liberty pointed out that sometimes there are transitional provisions which provide for a continuation of existing relationships, and it recommended that this matter should be reviewed in the next year to determine if there are any effects on NSPI operations from any ongoing transactions with the new owners of Emera Fuels.[33]

[128] Liberty also discussed the arrangement whereby NSPI sells to EES the natural gas that NSPI has available under contract, but which it does not use for generating electricity.

[129] Liberty stated in its Direct Evidence:

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[33]Exhibit N-97, pp. 67-68

Q. WHAT IS YOUR OPINION OF THESE ARRANGEMENTS?

A. The descriptions of the competition process and the resulting arrangements in the response to Liberty IR-99 were neither clear nor accurate (although NSPI corrected the inaccurate information in responses available on October 3, 2005). Our examination indicates that NSPI did not conduct a sufficiently competitive process in making its decision. This process and the arrangements that resulted from it were not consistent with good utility practice or evidently compliant with the Company's obligations under the Final Code of Conduct, Paragraph 6.1 of which provides that the Company will "... not ... offer any preference or favoured treatment to NSPI's affiliates ...".

Q. CAN YOU DESCRIBE HOW MARGINS AVAILABLE TO NSPI CHANGED BEFORE AND AFTER ENTERING THE ONE-YEAR AGREEMENT WITH EES?

A. Exhibit LCG-9 attached to this evidence presents information extracted from the parent company's Annual Report for 2004. The table shows that NSPI substitution of HFO for natural gas in fueling its power generation allowed the sale of gas for more than it cost, thereby producing a net negative gas cost. After EES became the exclusive purchaser of NSPI's gas, however, the benefit of such gas sales fell by half. At the same time, EES's margins were doubling.

. . .

Q. WHAT DO YOU MAKE OF THE FACT THAT THE ARRANGEMENT WITH EES AVOIDS THE NEED FOR NSPI TO SELL THE GAS IN THE U.S. MARKET?

A. The utility could and should sell its own gas, crediting all of the realized margins to its fuel-cost accounts, absent clear evidence that the intervention of a marketer like EES adds value in excess of the costs or lost margins that also come with the use of that marketer. The sales at issue here are reasonably typical off-system sales, which are routinely conducted by many utility companies in the U.S. Moreover, one should question whether the U.S. location of gas sales is the full reason behind the use of a marketer, given that EES appears to be using some of the gas purchased from NSPI to make sales within Canada.

. . .

Q. WOULD IT BE REASONABLE FOR NSPI TO SELL ITS GAS DIRECTLY TO PARTIES SUCH AS THOSE WITH WHOM EES EVENTUALLY TRANSACTS?

A. Yes. EES has a track record in the business, but it is a short one. It also has a staff, but duplicating its size and level of experience would not be that hard for NSPI. We have examined natural gas distribution utilities that make comparable off-system sales with very small staffs. Typical is a company we recently examined; it uses a staff of five people to conduct all of that company's gas-supply planning and capacity and commodity contracting. Those same five people also conduct a secondary-market program (off-system sales and capacity-release transactions) that involves about three times the volume that EES sells for NSPI. Our brief review of EES staffing confirms that they use a similarly small staff. Liberty has performed similar reviews at a number of other utilities, all of whom have secondary-market programs, with comparable findings. Making off-system sales is just not that hard.

. . .

Q. ASSUMING FOR THE MOMENT THAT NSPI SHOULD NOT SELL THE GAS ITSELF, WHAT SHOULD IT DO IN SELECTING ANOTHER PARTY TO CARRY OUT THAT FUNCTION FOR IT?

A. It should secure an arrangement through arm's-length bidding.

Q. WHAT DID YOU LEARN ABOUT WHETHER NSPI CONDUCTED SUCH A PROCESS?

A. We examined the documentation that NSPI provided about its solicitation process. That documentation exhibited a number of anomalies.

. . .

Q. WHAT DID YOU CONCLUDE ABOUT WHETHER THE DEALINGS WITH EES TOOK PLACE AT ARM'S LENGTH?

A. We concluded that the available information gave substantial reason to conclude that NSPI did not make an even-handed effort to give all the potential buyers an opportunity to compete on a comparable basis. Rather, the appearance from the documentation was that NSPI first took from three third parties their opening or "sticker price" positions, and only then asked its affiliate to stake out a position. Then, it took that position, which did not offer clearly superior terms and conditions, as a basis for deciding to negotiate with its affiliate to the exclusion of the others. In other words, EES appears from the documentation to have gotten an opportunity to make a refined offer that NSPI compared against the opening or first positions of the competitors.

(Exhibit N-97, pp. 69-78)

[130] Liberty also expressed the view that the arrangement between NSPI and EES did not accord with the Board's findings in the 2002 rate case. It stated that:

We believe that the agreement with EES raises problems under the 2002 order in the following respects:

- It treated gas sales as not representing a core utility function
- It transfers a major portion of that function to an affiliate
- It took away a key part of NSPI responsibility for gas sales
- It did so without substantial information addressing EES capabilities relative to other providers
- It did so without a full consideration of customer risk, conflict, and harm

- It reduced income available to NSPI

- The agreement with EES did not result from bidding or from what may be described as real competition

- It did so without prior Board approval.

We believe that the agreement fails to comport with good utility practice in the following respects:

- There was no apparent structured process for determining NSPI's capabilities to generate substantial margins through internal conduct of the function or any estimation of the difference in net benefits to be produced by such internal conduct

- There was not a sufficiently competitive process for awarding the business, assuming that it should have been conducted outside NSPI

- The affiliate received substantial advantages in what was not an arm's-length selection process.

(Exhibit N-97, pp. 83-84)

[131] With respect to Liberty's recommendation that there should be an audit of affiliate transactions as they impact NSPI costs and operations, Liberty explained this further in response to questions from the Board:

Q. Just on that point, I believe one of your recommendations is that there be an annual audit of affiliate transactions.
A. (Antonuk) Not necessarily annual, but periodic.

Q. What sort of -- when you talk about an audit of affiliate transactions, you have comments in here concerning affiliate transactions. In your view, how would an audit of affiliate transactions differ from, in essence, what you have done in order to be able to make your comments that you made in here about the affiliate transactions, how would that differ?
A. (Antonuk) Well, the first thing it would do is typically it would proceed over the course of probably more like a 5 to 6 month period, so that there could be a more, from an audit perspective, orderly and careful flow of information than is ever going to be possible in a rate case with the deadlines that, from an affiliate's audit perspective, frankly just don't work. You know, if you've got only so much time to ask a DR and you can't follow it up and you can't go back and sit down with management and say "What about this? Here's my concern about that", you can't have -- you just can't get to the bottom of these issues realistically in a rate case construct primarily because it's a -- forgive me for saying this, it's kind of a legal-driven process rather than a business and management-driven process. And also because a rate case, for good

reasons, has to operate on deadlines. The other thing it would do is it would not limit you to looking at things that do or don't have a direct impact in a test year but still may be influencing over the long term utility costs in a very significant way, you know, cost allocations, for example. You know, whether common organization structures exist to serve utility/non-utility affiliates and whether, in fact, the company's allocating cost properly. When they're dealing with third parties, you get the code of conduct issues, and an affiliate's audit usually also goes into those and validates that the company's not only meeting the express limits of the code of conduct but it's also doing what it needs to do to encourage third parties to believe that there is true competition. So it's those kinds of issues. Those audits often end up coming back and having relevance in a rate case if you find something wrong and there happens to be a rate case, you know, that shortly proceeds [sic] it. But the real benefit of them, I think, is it gives a Commission or, in your case, a Board, confidence over the long run that the utility is being run as a utility and not as an entity that exists to provide profit opportunities for affiliates.

. . .

Q. Excuse me, your recommendation doesn't just -- is not just confined to energy affiliates, is it?

A. (Antonuk) No, I don't think it should be. No, it should not be. It should address them all, although when you're doing a work plan for an affiliate's audit, if the non-energy stuff is minor in terms of potential consequence, you would -- obviously your work plan would call for very little time on that. And, like I said, we have not gone through that process of sort of saying where are all the risks. I think we do have a pretty good handle on where the energy risks are, and a lot of them are addressed in the report. The other thing an affiliate audit does, which I think is something that's very hard for a lot of people to see, is this. When you have affiliates who are dealing with a third party community like energy buyers and sellers, and a utility that's dealing with them, you may not see any transactions between the utility and the affiliate, but what we have found in the past sometimes is what you do see is there's a third party out there, maybe a big supplier, who's given the affiliate a good deal and is charging the utility more. Now, I'm not saying that's common, you know, most people don't do that, but we have discovered that. But that's something where you would have to look even where there aren't direct transactions between a utility and a non-utility affiliate and say is there some common third party out there that's providing a vehicle for distribution of costs or revenues in a way that's inappropriate. And I'm not suggesting there's -- you know, that we have reason to think that there's any of that kind of conduct going on here, but it is one of the things that as a matter of due diligence we believe needs to be checked periodically.

Q. Given your time frame, 5 to 6 months, it likely wouldn't be practical to do this on a yearly basis.

A. (Antonuk) No, and we don't think they're necessary on a yearly basis. You know, I guess it's in my interest to say frequently, but, you know, if they're on -- using people who come in and do a good look every three or as long as five years is fine provided whoever's doing that is leaving the staff with kind of, you know, a checklist to use in between to let the staff see if any of the base lines of performance or transactions are changing in the interim. So you could go with maybe a five-year cycle and then have the staff just run through the diagnostic checklist with the company every maybe 18 months or even 2 years.

Q. In your view, is this a significant recommendation? I mean, is this something you feel strongly about that should be done?
A. (Antonuk) Yes. And that's based both on our general belief in the importance of them, and also in the specific things we've seen here, even more so the latter in this case is the specifics we've seen.

(Transcript, November 29, 2005, pp. 2433-2438)

[132] During Mr. Connors' cross-examination of Liberty, he asked about any proposed adjustments to the revenue requirement as a result of affiliate transactions:

Q. Thank you. Now, Mr. Adger, you've made some comments with regard to affiliate transactions and some questions about certain aspects of the historical relationships. Would you agree that your company has not proposed any adjustment to the test year revenue requirement with regard to those matters?
A. (Adger) That's correct.

Q. And would you also agree with me that relations between Nova Scotia Power and any affiliates within 2005 you're not suggesting that that affected in any way customer rates in 2005?
A. (Adger) I think I have to qualify a response to that, because we remain concerned that the structure for the sale of Nova Scotia Power's gas that it receives from **[confidential]** is -- does not maximize the value of those gas sales. However, the rates were set based on some estimate of it, so that lack of value maximization affects Nova Scotia Power but not the customers in 2005.

(Transcript, November 29, 2005, pp. 2467-2468)

[133] Mr. Connors also asked Liberty about its recommendations that there be periodic audits of affiliate transactions:

Q. And are you aware that a chartered accountant firm independent of the company already conducts an annual audit of compliance with the code of conduct?
A. (Adger) I was not specifically aware of that but ---

Q. No. And are you aware -- so I take it then you would not be specifically aware that that company has provided reports for the past year and before that we've had several annual reports filed with the Board in that regard by that accounting firm?
A. (Adger) I would expect that to be the case. I would say, though, that it has been our experience that accounting firms sometimes don't find things that people with more expertise in those kinds of transactions found.

Q. Would the SEC have more expertise in the area of affiliate transactions?

A. (Antonuk) No.

Q. Not at all?
A. (Antonuk) No. Well, I can't comment on their expertise. Their level of scrutiny, I think, is pretty weak, though, over affiliate transactions.

Q. I see. So, if I suggested to you that the company underwent a regular audit of affiliate transactions in the past year by the SEC, an audit that took place over a number of months, you're going to say that the outcome of that is something the Board shouldn't pay attention to?
A. (Antonuk) No, let's get on the straight -- on the same question. I thought you meant the United States Securities and Exchange Commission.

Q. That's exactly who I'm talking about.
A. (Antonuk) Yeah. I don't think their audits of affiliate transactions are particularly effective at finding the kind of things we're talking about.

Q. I see.
A. (Antonuk) We've looked at many of them.

Q. You understand, but were you aware of the fact that there has been an affiliate audit?
A. (Antonuk) I would not expect there not to be, I'm just saying that I don't see how it bears on what we were talking about.

Q. I see.
A. (Antonuk) We know that's the case with the utilities we've examined, and if you look at our reports there are a lot of things we find that they don't -- never even choose to look at.

Q. If I suggest to you the affiliate audit conducted by the SEC raised none of these issues ---
A. (Antonuk) I'd say that's pretty typical of every -- virtually every Liberty report you see where we find material problems. That's why I said I don't think the SEC is very deep or effective at looking at these issues. Their concern isn't utility customers.

(Transcript, November 29, 2005, pp. 2468-2470)

[134] Liberty expressed concerns that the arrangement between NSPI and EES was not entered into on an "arm's-length basis":

> ... the available information gave substantial reason to conclude that NSPI did not make an even-handed effort to give all the potential buyers an opportunity to compete on a comparable basis .... In other words, EES appears from the documentation to have gotten

> an opportunity to make a refined offer that NSPI compared against the opening or first positions of the competitors.
>
> (Exhibit N-97, pp. 77-78)

[135] Liberty stated that the process and arrangements with EES were not consistent with good utility practices and, further, were not in compliance with the Company's Code Of Conduct.[34]

[136] Liberty suggested that NSPI should be selling its own gas, and "... crediting all of the realized margins to its fuel-cost accounts, absent clear evidence that the intervention of a marketer like EES adds value in excess of the costs or lost margins that also come with the use of that marketer."[35] Alternatively, Liberty expressed the view that, if NSPI does not sell its own gas, but selects another party to do it, then NSPI should do so through an arm's-length bidding process.[36]

3.5.3 Findings

[137] The Board has considered whether or not it should direct NSPI to re-assume the selling function for its natural gas not utilized in the generation of electricity. NSPI has stated in its Rebuttal Evidence of November 7, 2005, that it needs "... an arrangement that locked in the value of the market. The RFP and resulting contract did that, securing a premium to an M3 published index in the winter months and no less than market driving

[34]Exhibit N-97, p. 69

[35]Exhibit N-97, pp. 70-71

[36]Exhibit N-97, p. 73

[sic] other months..."[37] NSPI argues that EES offered greater value than others did, and given the uncertainties with supply and demand, the best price and flexibility was obtained with the EES contract.

[138] The Board notes that Undertaking U-84, which sets out the details of the margins earned by EES on its sales of natural gas and power, indicates that the income arising from the gas EES has purchased from NSPI is a very small percentage of EES's total business. It is clear to the Board, based on Undertaking U-84 and other evidence filed during the hearing, that the resale of NSPI's gas constitutes a very small component of EES's operations, and that in order for NSPI to assume the task of selling its own natural gas, it would be obligated to establish the necessary internal infrastructure, including employing the necessary number of employees possessing the skills to deal effectively in the natural gas markets.

[139] NSPI has committed to engaging in an RFP process to select a new party to handle its natural gas, and that the selection of the new party will be based on an objective assessment of the RFP responses by an independent third party. It is possible that EES, or another affiliate of NSPI, could be chosen to handle the NSPI natural gas contract; however, the choice will be made on an arm's-length basis by an independent third party.

[140] Given these circumstances, the Board is not prepared at this time to require NSPI to assume direct responsibility for selling its surplus natural gas. However, the Board will monitor the transactions and the relationship between NSPI and the company selected

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[37] Exhibit N-153, p. 49

to handle NSPI's natural gas, particularly if the arrangement should be with an affiliated company.

[141] Liberty has recommended that NSPI conduct a study to determine the feasibility of establishing an in-house capability to sell its own gas.

[142] The Board agrees with this recommendation and directs that NSPI carry out such a study and to file it with the Board by August 31, 2006.

[143] Liberty also recommended that periodic audits be carried out on affiliate transactions and NSPI's relationships with Emera and Emera subsidiaries.

[144] In its 2005 rate decision, the Board stated:

> The Board also notes the concerns expressed with respect to other affiliate transactions involving energy and fuel. It is evident from the issues raised that reviewing NSPI's annual filing on affiliate transactions solely by an accounting firm, however well qualified, is likely insufficient. Accordingly, in addition to the form of review on this information performed in the past, the Board, in future, will also retain fuel audit experts to examine and express their opinions on these types of affiliate transactions, including export sales and natural gas sales.
>
> (Board Decision, March 31, 2005, pp. 63-64)

[145] Liberty outlined, in oral evidence, how the audit of affiliate transactions and relationships should be conducted. Primarily, it envisages an audit carried out every three to five years which would take a few months to complete. This would allow the audit to proceed in an orderly and thorough manner, which would not be possible if it were being conducted as part of a rate case. The audit, which would review significant transactions with all affiliates, would be designed to review items which may not directly impact test year figures, but which may have significant long term cost implications for NSPI.

[146] In Liberty's opinion, the real advantage of these periodic audits is that they will provide the Board with meaningful assurances that NSPI is being run properly as a utility, and not as a vehicle "... that exists to provide profit opportunities for affiliates."[38]

[147] The Board accepts the recommendation of Liberty to implement a process of detailed, periodic audits of affiliate transactions. Due to Liberty's extensive knowledge of NSPI, gained as a result of its work during the last two years, the Board will retain Liberty to carry out the first audit. During 2006, the Board will request Liberty to prepare a detailed work plan for the first audit, including the estimated time and budget, as well as an appropriate commencement date. The Board directs that the work plan be filed with the Board by June 30, 2006 for Board approval. The Board intends this audit to be carried out on a professional basis by experienced experts in utility matters, including the energy and fuel functions, as well as affiliate transactions. NSPI will be consulted during this process and its opinions solicited. The Board, in planning the commencement date for the first audit, will give consideration to other time commitments which may be facing NSPI.

[148] The reason the Board considers this audit to be an important step is because NSPI's parent, Emera, has become a large multi-faceted organization, with many affiliates, and NSPI engages in numerous transactions with some of these affiliates. In order to properly carry out its mandate pursuant to the **Public Utilities Act**, the Board must be able to satisfy itself that these inter-affiliate transactions are being conducted in accordance with

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[38]Transcript, November 29, 2005, p. 2435

the Code of Conduct and that they are also properly accounted for in the records of NSPI, thereby ensuring that NSPI is receiving all profits to which it is justly entitled.

[149] The detailed audit of affiliate transactions is not meant to replace the annual reporting required under the Code of Conduct. Rather, these annual filings will be extremely useful in the design of the work plan for the audit of affiliate transactions, and the Board will ensure that there is no duplication of effort between PWC and Liberty, with respect to the periodic audit of affiliate transactions.

3.6 Point Tupper Marine Terminal

3.6.1 Submissions - NSPI

[150] In its Direct Evidence, NSPI provided a brief outline of the Point Tupper Marine Terminal ("PTMT"):

> The Point Tupper Marine Terminal (PTMT) is a bulk unloading facility located adjacent to the Point Tupper generating station. PTMT can accommodate gearless vessels, or bulkers, which were previously not an option for NSPI. This option increases competition among coal suppliers and provides access to lower cost supplies of coal, and can result in suppliers revising bids to compete with alternative supply basins. The location and design of the terminal were chosen to:
>
> - Substantially reduce demurrage charges through faster unloading capability;
> - Eliminate rail transportation costs from the port to the Point Tupper plant; and
> - Allow for bulkers which usually have lower transportation costs and allow shipments from more distant ports.
>
> The PTMT began commercial operation early in 2005, receiving the first vessel as part of the commissioning process in January, ahead of schedule. Following competitive bids, NSPI chose Savage CANAC Corporation, the Canadian affiliate of a leading US service provider

> in the bulk material handling industry, to manage the operation of the marine terminal. The parties entered a 10-year contract starting April 1st, 2005....
>
> (Exhibit N-1, pp. 58-59)

[151] In its Rebuttal Evidence, NSPI furnished additional information about the PTMT, including why it was built:

> When NSPI began to import coal in 2001, there were no coal import facilities in the Strait of Canso to support delivery to the Trenton and Port Tupper generating stations. NSPI was able to negotiate an agreement with Martin Marietta to unload coal at its aggregate operation in Aulds Cove. The Martin Marietta facility was relatively small and not equipped to handle large vessels. Only self-unloading vessels could be unloaded at the Martin Marietta facility and demurrage was always due as the vessels could not be unloaded at the standard contract rate of 2,500 tonnes per hour. Coal from the Martin Marietta facility had to be railed or trucked to Point Tupper and Trenton. Further, there was very limited storage at the Martin Marietta facility.
>
> As noted in EVA's review of NSPI operations, NSPI negotiated a 30-month agreement with Martin Marietta that started in October 2002. The agreement provided "sufficient time for NSPI to determine its best long-term for supplying Trenton and Point Tupper." EVA noted "(t)he Martin Marietta facility as configured provides a good stop-gap alternative for NSPI but may not make sense long-term because of the inherent inefficiencies in how the vessels are unloaded and its limited storage capacity." In order to increase storage at the Martin Marietta facility, a second pad was added on an area away from the port and rail link but was not desirable as NSPI incurred an extra cost every time it was used.
>
> NSPI conducted a systematic process for identifying alternatives to the Martin Marietta facility. NSPI advertised for parties interested in providing terminal services and/or bidding to develop a terminal at Point Tupper. NSPI determined the least cost strategy to be a terminal at Point Tupper, and selected a third party to own and operate it.
>
> As the Board is aware, NSPI's plan for the terminal faced certain challenges when it was not able to consummate an agreement with the selected third party. NSPI, following discussions with the Board, decided to go forward with the terminal outside of the traditional capital approval process in order for the terminal to be completed in a timely manner. NSPI estimated that it would incur \$3 to \$4 million in additional costs in 2005 if it delayed development of the facility. At the time, NSPI committed to attempt to divest the terminal once it was operational or return to the Board to ask that the cost of the facility be put into rate base.
>
> The Board, in a letter dated January 22, 2004 noted that "the Board has no objection to NSPI constructing the terminal outside rate base. At such time as NSPI applies to the Board to have the terminal included as part of rate base, or applies to the Board to have the terminal sold and leased back to NSPI the Board will determine whether or not the proposed transaction, and its related costs, is appropriate after performing its normal review procedures." NSPI proceeded with the terminal and completed construction in a timely

> manner such that the unloading of vessels destined for Trenton and Point Tupper was accommodated by PTMT upon the expiration of the Martin Marietta agreement.
>
> While NSPI has not abandoned its efforts to sell the terminal, it has entered into a 10-year operating agreement with Savage for its operations. The Savage contract was produced for review as part of this proceeding.
>
> . . .
>
> NSPI is still marketing PTMT and hopes to sell it to a third party. Absent that, NSPI will ask the Board to put the capital into rate base. In the interim, capital recovery on PTMT is appropriate given the undisputed value it has provided NSPI with respect to both direct saving, which NSPI estimates to be **[confidential]** in 2006 alone when NSPI is purchasing relatively little of its fuel requirements from non-traditional sources, and indirect costs related to the increased competition in coal supply.
>
> (Exhibit N-153, pp. 43-47)

[152] In its rate application, NSPI has included in the fuel expense an amount of $2.3 million, which represents the equivalent to a capital charge recovery on the terminal. These funds are not being paid to Savage, but represent a capital recovery charge on the terminal. In essence, the charge represents a recovery to NSPI for its capital related expenses in carrying the facility. The facility has not been approved for addition to rate base, as set out above.

[153] NSPI, in its Closing Argument, stated that "... NSPI is seeking to recover in its fuel expense a $2.3 million proxy fee for capital recovery while NSPI uses the full capacity of the PTMT for the benefit of customers."[39]

[154] NSPI took issue with both Dr. Raschke and Sharon Hennings, of Brubaker and Associates Inc., with respect to their proposed disallowances relating to the PTMT and, in particular, "... relating to the inclusion of a proxy for capital cost in the fuel expense

[39] NSPI, Redacted Closing Argument, p. 41

calculation. Neither consultant has expertise in marine terminal design, capacity, and operation, and both appear to understand the significant benefits to NSPI and its customers that PTMT delivers."[40]

[155] In UARB IR-61, NSPI set out the breakdown of the $2.3 million capital recovery charge. It includes an estimate for depreciation, interest expense on the short-term debt to finance the PTMT, a rate of return on the equity component invested in the terminal, and the related income tax effects.

[156] With respect to the claim by Ms. Hennings that NSPI does not utilize 100% of the capacity and thus should not be able to recover the total amount of the capital expense, NSPI, in its Closing Argument, quoted from its response to SEB IR-197:

> In order to minimize demurrage, PTMT was designed such that belted self-unloading Panamax vessels could off load at a rate of 3,000 tonnes per hour. The unloading capacity of the crane used for bulker-type vessels was designed for approximately 800 tonnes per hour, which balances terminal capital costs and demurrage charges for this type of vessel. PTMT must agree to allow delivery of nominated ships within a period the length of which is negotiated between the parties. The more distant the source, the longer the period must be. For example, a 20-day window is not uncommon for deliveries from Indonesia. In order to avoid demurrage, NSPI minimizes the overlapping of delivery windows, which limits the number of ships that can be accommodated. **The PTMT maximum design capacity for storing solid fuel is 164,000 tonnes. This capacity is just sufficient to unload vessels and maintain the flow of solid fuel to the plants. The inventory storage and daily feed storage areas for the Point Tupper station is 44,000 tonnes.** The Point Tupper unloading area under the unloading trestle is 50,000 tonnes. The Trenton unloading storage area under the trestle holds 70,000 tonnes, which allows for a full bulker Panamax vessel to be unloaded when the area is empty. The Trenton storage volume is transferred via a rail shunt to the Trenton generating station five days per week. The terminal is not designed to handle commodities other than solid fuels. [Emphasis added in original]
>
> (NSPI, Redacted Closing Argument, p. 44)

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[40] NSPI, Redacted Closing Argument, p. 41

[157] NSPI stated that the above information makes it clear that Ms. Hennings' views concerning the capacity of PTMT are incorrect.[41]

3.6.2 Submissions - Intervenors and Liberty

SEB

[158] Ms. Hennings, an expert witness appearing on behalf of SEB, discussed the PTMT in her Direct Evidence:

> Q. Please provide background information about NSPI's Point Tupper Marine Terminal.
>
> A. Point Tupper Martine Terminal (PTMT) was completed in early 2005, at a total cost of $34.6 million, (Avon IR-56). NSPI is the current owner of PTMT, (NSDOE IR-64). NSPI is currently trying to sell PTMT, and it has not been its intention to own the terminal. NSPI claims that the costs included in the 2006 forecast for PTMT are justified by savings on its Point Tupper and Trenton coal receipts, as compared with its coal receipts using the dock at Auld's Cove.
>
> Q. Could the PTMT handle more than the current requirements of Point Tupper and Trenton?
>
> A. Yes, the PTMT could handle several times the current requirements of these generating plants...
>
> Q. What ratemaking treatment is available for the capital costs of the PTMT?
>
> A. For an asset included in the utility's assets, regulatory bodies sometimes eliminate part of the investment costs from rate base if the utility has built excess capacity that is not both used and useful. The used and useful criteria could be applied to the PTMT annual cost of capital of $2.30 million per year.
>
> NSPI has constructed an asset that it has proposed to charge as though it is part of rate base. It has calculated both depreciation and rate of return in developing a cost of $2.3 million to pass to ratepayers. From the bid information in the request for proposals when NSPI attempted to sell this asset, it has at least 50% more capacity than will be used during 2006 for utility purposes. Based on the delivery capability of this asset, it is capable of several times more delivery capacity than necessary for utility operations. The entire PTMT facility may only have NSPI as its sole customer during the year, so PTMT will likely qualify as being used by NSPI. However, only

[41] NSPI, Redacted Closing Argument, p. 44

> part of the shipping capacity is useful to NSPI. Thus, PTMT has excess capacity for utility purposes. The cost of this excess capacity should not be passed through to ratepayers in 2006.
>
> Q. What level of elimination of capital costs are you advocating?
>
> A. NSPI's $2.3 million proxy for the cost of capital should be reduced by at least one third ... Based on the delivery capability of the asset the Board may wish to consider an even greater reduction.
>
> (Exhibit N-91, pp. 2-5)

[159] SEB, in its Final Confidential Fuel Related Argument, stated that NSPI is seeking to recover not only the operating costs which it pays to Savage, but also the $2.3 million related to the capital costs of the PTMT. SEB believes that the Board should adopt the recommendation of Dr. Raschke that no capital recovery be allowed to NSPI in the 2006 test year because none of the PTMT's capital costs have been included in rate base. SEB also indicated that, although Ms. Hennings had recommended only a partial disallowance, she could also support Dr. Raschke's recommendation.

[160] SEB explained these points as follows:

> NSPI has indicated that it has not abandoned its efforts to sell the terminal, and it has not yet applied to the Board as contemplated in the Board's letter of January 22, 2004. Accordingly, NSPI's inclusion of $2.3 million on account of capital for the PTMT in fuel costs is merely a back door route to recovery of its capital where the Board has not yet conducted a review of the capital expenditures for PTMT and has not included it in rate base. In these circumstances, SEB submits it is highly inappropriate to allow for this capital cost recovery as a part of fuel expense.
>
> Depending on whatever arrangements NSPI may ultimately enter into by way of sale and leaseback, NSPI could easily end up over-recovering its costs from ratepayers. The Board is simply not in a current position to allow for this recovery, as it specifically stated in its January 22, 2004 letter. Section 35 and subsection 35A(1) of the Act require NSPI to obtain Board approval for any new construction, improvements or betterments in or extensions or additions to its property used or useful in furnishing, rendering or supplying any service which requires the expenditure of more than $25,000, or approval of an annual capital expenditure program.

Subsection 42(1) of the Act provides that the Board shall fix and determine the appropriate rate base for NSPI, and subsection 42(2) indicates that in establishing a rate base the Board shall determine the value of the physical assets of the public utility in accordance with the provisions of the Act, and sets out various factors that the Board should consider.

To date the Board has not determined "whether or not the proposed transaction, and its related costs, is appropriate", nor has it conducted its normal review in this regard. In these circumstances NSPI's claim for capital cost recovery is not supportable, and indeed likely not permissible.

However, if the Board is somehow of the view that it is appropriate and permissible for NSPI to recover a portion of its capital through its fuel costs, SEB submits for the reasons specified in Ms. Hennings' Direct Evidence, pages 2 through 5 (Ex. N-90), that the $2.3 million be reduced by one-third, i.e. $767,000. It appears that PTMT will certainly not be fully utilized, and various bidders who responded to NSPI's RFP to own and/or operate PTMT appear to be of the view that the facility could accommodate up to **[confidential]** million tonnes of coal and also possibly be utilized as a trans-shipping or off-loading base for other customers (see Ex. N-205). In essence, as described above under the description of the "used and useful" test, PTMT is not fully "used and useful" for NSPI's regulatory purposes, and NSPI should not be entitled to a return on its fully booked cost in 2006.

(SEB, Final **Confidential** Fuel Related Argument, pp. 54-55)

[161] SEB submitted that it would be completely inappropriate to allow a utility to recover the costs of an asset not in rate base:

With respect to the argument that PTMT has not been approved for recovery in rate base, NSPI states at page 45 that:

> It is appropriate from a regulatory rate making perspective to include recovery of the operating component as well as a proxy for the capital component of the investment within the context of the fuel expense.

NSPI provides no citation to support this bold assertion, and no evidence of where such treatment has been allowed. SEB respectfully submits that this would in fact be completely inappropriate from a regulatory rate-making perspective.

(SEB, Final **Confidential** Fuel Related Rebuttal Argument, pp. 16-17)

Avon

[162] Avon, in its Closing Submission, had the following to say with respect to the PTMT:

NSPI has constructed the Point Tupper Marine Terminal (PTMT) for the stated purpose of accommodating larger vessels and expanding the range of supply sources for import coal. At the present time, NSPI has been trying to sell the PTMT and it has not applied to the Board to have the terminal included as part of the rate base. NSPI has entered into a ten year operating agreement with Savage Canac for operation of the PTMT.

NSPI has accounted for the payments to Savage Canac valued at **[confidential]** for PTMT and **[confidential]** for Trenton in its fuel costs and in addition, it is seeking to recover $2.3 million as equivalent to a capital cost. It is this latter amount which we dispute.

. . .

Dr. Raschke has submitted that NSPI should not be permitted to include in its fuel costs any of this $2.3 million capital recovery for PTMT. While NSPI's rebuttal evidence suggests that Dr. Raschke has not offered evidence with respect to the actual capital costs and NSPI's prudence or imprudence in building the facility, the fact of the matter is, this is not the forum to do so. If and when NSPI applies to have the PTMT brought into rate base, it is at that time that Dr. Raschke may have something further to say.

. . .

Sharon Hennings offered an alternative recommendation with respect to the PTMT suggesting that the "used and useful" criteria could be applied to disallow at least 1/3 of the claimed cost on the basis that PTMT has excess capacity for utility purposes.

Ms. Hennings also confirmed in her testimony that she supported the recommendations of Dr. Raschke that capital recovery be disallowed for the PTMT in 2006 because the capital costs have not been included in the rate base, indicating that his recommendation is supported by the letter of January 22, 2004, from the Board. This letter was referred to by NSPI in its rebuttal evidence and filed subsequent to Ms. Hennings' evidence.

It is telling that the PTMT amortization costs, "equivalent to capital costs" were included in forecast 2005 results even though NSPI did not apply for these costs to be included in rates and the Board made no direction in this regard.

There is no regulatory precedent for including the PTMT amortization costs as an equivalent to capital in the fuel budget. We respectfully submit these ought to be disallowed in their entirety.

(Avon, Redacted Closing Submission, pp. 19-21)

Province

[163] In its Closing Submission, the Province expressed significant reservations concerning NSPI's claim for a $2.3 million capital recovery:

NSPI is seeking $2.3 million for what it characterizes as a fuel expense which is the equivalent to capital recovery on the Point Tupper Marine Terminal. NSPI's position is that if the Point Tupper Marine Terminal were owned by a third party, capital recovery would be included in lease payments, and thus form an operating expense that would flow into its fuel costs. It argues that since the Point Tupper Marine Terminal is generating transportation related savings in excess of the $2.3 million claimed, its capital related recovery is justified. It is troublesome that NSPI is seeking capital recovery on an unapproved capital asset, and that the amount that it seeks to recover in 2006 along is well in excess of the $1 million threshold for identifying capital projects that require separate review and approval.

Expected savings generated by a capital asset might provide justification for the approval and construction of the asset, but they should not be used as a justification for capital recovery without approval. While NSPI's position might very well turn out to be correct, that a cost benefit analysis would support this capital asset, the Province does not believe that the Board has been provided with a cost benefit analysis of the same quality as would be expected to support an application for a capital project. The Province is also not certain that all of the potential costs associated with the facility have been thoroughly presented. For example, the facility supports the Trenton generating station and there may very well be additional costs incurred given that the Point Tupper facility is further away from Trenton than the Martin Marietta facility at Auld's Cove.

The argument that capital costs would be imposed on NSPI if the facility was owned by a third party is also not satisfactory. If that third party was Emera or another NSPI affiliate, surely such an arrangement would warrant close regulatory scrutiny. It should not be any different when the asset is owned by NSPI's unregulated split personality.

The $2.3 million claimed by NSPI is derived from the asset value and a depreciation rate that has not been approved by the Board and that could be varied by the Board, if and when NSPI ever does see fit to move forward with a proper regulatory review of this asset. Without a proper regulatory review one cannot be certain that the claimed $2.3 million is not an over recovery, regardless of the level of operational savings that the asset purportedly generates. The Province submits that NSPI's capital recovery relating to the Point Tupper Marine Terminal should be tied to a directive that it proceed to apply to the Board for approval to include the asset in its rate base. Furthermore, the Board should provide that any capital gain, should the facility be sold in the interim, be credited to NSPI's regulated personality.

(Province, Redacted Closing Submission, pp. 22-23)

Liberty

[164] Liberty, in its Direct Evidence, reviewed the solicitation and evaluations in connection with the appointment of Savage to operate the PTMT:

Q. APART FROM THE LONG-TERM COAL CONTRACT SOLICITATIONS THAT YOU HAVE JUST BEEN DESCRIBING, PLEASE LIST ANY OTHERS THAT YOU EXAMINED.

A. We reviewed the solicitation and evaluations associated with the selection of Savage to own and operate the new Point Tupper Marine Terminal. While the solicitation was on the basis of selecting a new owner for the terminal, NSPI currently still owns the terminal.

Q. WHAT DID YOUR REVIEW SHOW WITH RESPECT TO SUFFICIENCY OF THE SOLICITATION PROCESS?

A. Liberty found the solicitation process associated with the Savage agreement to be appropriate. The substantive documentation that NSPI provided showed the solicitation and the response from bidders to be comprehensive and thorough. Liberty did observe, however, that the documentation associated with the Savage solicitation and award process contained the same administrative deficiencies as described above related to coal and petcoke procurement.

The original bidders list contained 19 firms, four of which responded. The Savage proposal was clearly the most comprehensive, and offered the lowest operating costs. Liberty found a clear summary of the issues related to each of the bids from all suppliers. NSPI did express some reservations about the Savage bid. At this point in the documentation, the information became sketchy. It was not possible to determine how or whether NSPI resolved its concerns with Savage. The only point that was clear was that the competition narrowed to two providers, but no basis for this was provided. The crucial point is that the documentation provided contains no analysis indicating why the business was ultimately awarded to Savage. In addition, as with the majority of coal and petcoke procurements, there is no management approval documentation supporting the award to Savage.

(Exhibit N-83(a), pp. 48-49)

[165] In cross-examination by Mr. Connors, Liberty confirmed that it was not recommending a disallowance of any of the PTMT charges.

3.6.3 Findings

[166] The Board has considered the evidence surrounding the PTMT. The main concern is related to the capital recovery charge of $2.3 million which NSPI wishes to recover as part of its fuel costs for the 2006 test year.

[167] Dr. Raschke was of the view that NSPI should not be permitted to include any of the $2.3 million in its fuel costs because the PTMT is not in rate base. Ms. Hennings, on the other hand, was of the opinion that the PTMT has excess capacity, and that there should be a disallowance of a portion of the $2.3 million cost associated with the facility, based on the "used and useful concept". She stated that

> ... regulatory bodies sometimes eliminate part of the investment costs from rate base if the utility has built excess capacity that is not both used and useful. The used and useful criteria could be applied to the PTMT annual cost of capital of $2.30 million per year.
>
> (SEB, Exhibit N-90, Evidence of Sharon K. Hennings, p. 4)

[168] The Province expressed reservations about allowing a recovery concerning an asset which has not been approved for inclusion in rate base.

[169] Liberty did not recommend any disallowance with respect to the $2.3 million capital recovery. However, the Board notes that Liberty criticized the documentation associated with the solicitation and award process, finding that it contained the same type of administrative deficiencies as observed in the coal and petcoke procurement process.

[170] To the Board's knowledge, NSPI's request for a capital recovery charge in relation to a non-rate base asset is extremely unusual and perhaps unprecedented. The **Public Utilities Act** clearly contemplates that all assets of a utility which are used and useful in supplying a regulated service shall be included in the rate base fixed by the Board with respect to that particular service. Furthermore, **s. 45** of the **Act** provides that a public utility is entitled to earn a just and reasonable return on the rate base fixed by the Board, and to recover reasonable and prudent operating expenses. There is nothing in **s. 45** or

elsewhere in the **Act** which entitles a public utility to recover capital-related charges in relation to assets which it owns outside of its approved rate base. Accordingly, in the Board's view, it would be improper to allow the recovery of the $2.3 million in fuel expense. Otherwise, a utility could hold assets outside its rate base even though those assets were being used to provide a regulated service. It could recover the capital-related charges through rates even though the Board had never approved the value of the asset for inclusion in rate base, or for depreciation purposes. Having proceeded in this fashion, the utility could then sell the asset without having to allocate to its customers any of the profits realized on the sale. This would be an intolerable situation which, in the Board's view, is simply not compatible with the intent or express provisions of the **Act**.

[171] The Board hastens to add that it is not suggesting any improper motive on the part of NSPI. The evidence clearly indicates that NSPI built the PTMT with the intention of selling it. In the meantime, it has entered into a contract with a third party to operate the terminal and the Board is satisfied that NSPI's customers are benefitting from the arrangement. Moreover, despite the evidence of Ms. Hennings, the Board is not persuaded that the terminal was designed to have excess capacity, although this question need not be definitively addressed unless and until NSPI applies to have the PTMT included in rate base. Should NSPI make such an application, the Board is prepared to consider at that time whether, in determining the amount to be included in rate base, an allowance should be made for deferred capital charges having regard to the fact that the

terminal has, since the commencement of its operation, been devoted exclusively to the receiving and unloading of coal for NSPI's Trenton and Point Tupper generating plants.

3.7 Natural Gas Resale Benefit

3.7.1 Submissions - NSPI

[172] NSPI has a long-term contract with a supplier for the purchase of natural gas. When the cost of natural gas exceeds the cost of other fuel types burned by NSPI in its generation facilities, the Company resells the natural gas and applies the proceeds to reduce its overall fuel costs.

[173] During the hearing, as previously indicated, NSPI announced it had reached a settlement with its supplier on the pricing and supply arrangements of natural gas, as well as other issues under the long-term contract. The settlement avoided the risk to both parties of an arbitrated resolution. While the details of the settlement are of an extremely confidential nature (and were treated as such during the confidential sessions of the hearing), the Company did issue the following public news release to the media, investors and financial institutions:

> **New Gas Pricing Agreement Reached by Nova Scotia Power**
>
> Halifax, NS, November 21, 2005 - Nova Scotia Power Inc. (NSPI) announced today that it has reached an agreement with its supplier on pricing for natural gas under an existing long-term natural gas purchase agreement.
>
> As a result of the agreement, NSPI will lower its 2006 fuel forecast by $22 million. This will reduce the Company's 2006 rate application from an average increase of approximately 15 per cent to approximately 13 per cent. NSPI has filed supplementary evidence with its regulator, the Nova Scotia Utility and Review Board (UARB).

> "This agreement is good news for Nova Scotia Power customers," said Chris Huskilson, President and Chief Executive Officer of Nova Scotia Power. "Given market conditions similar to today, the customer benefits from this agreement will continue for several years."
>
> The financial benefits of the agreement will vary based on world energy prices. Nova Scotia Power will propose to the UARB that should its 2006 fuel costs be lower (as a result of this agreement) than the amount the regulator ultimately provides for in the rate decision, the difference will be refunded or credited to customers.
>
> The agreement provides NSPI with natural gas at a discount to current world market prices. By having the option to resell the gas, NSPI and its customers can gain financial benefit.
>
> The contract - which began in 2000 and runs until 2010 - calls for up to approximately 61,600 MMBtus of natural gas per day to be supplied to Nova Scotia Power. The contract was subject to a price re-determination on November 1, 2004. With both Nova Scotia Power and its supplier unable to come to terms last year, the matter was referred to binding arbitration. The two companies reached agreement in advance of any arbitration decision. The UARB has been provided with details of the agreement which is confidential for competitive reasons.
>
> "This agreement is more than a year in the making," added Mr. Huskilson. "Customers are being asked to cover skyrocketing fuel costs - it's only fair they receive the benefit of this fuel contract gain by Nova Scotia Power."
>
> This agreement also results in a favourable adjustment to NSPI's fuel expense for 2005. Consequently, as a result of this agreement and other factors, including warmer weather in the fourth quarter, NSPI has revised its financial forecast earnings for 2005 and now expects earnings to be approximately $15-20 million lower compared to 2004.
>
> (Undertaking U-43)

[174] On a confidential basis, NSPI filed with the Board, and with intervenors who signed confidentiality agreements, Supplementary Evidence setting out the terms of the settlement and its estimated impact upon the 2006 test year fuel forecast.[42] While NSPI stated that the settlement will not eliminate all uncertainty respecting the Company's future gas supply costs, or the expected margin that can be obtained on the resale of any gas not consumed by the Company, it recognized that stakeholders would like some assurances that if results turn out better than originally forecast, the benefits would accrue to NSPI's

[42]Exhibit N-187

customers. After NSPI provided its estimate of the natural gas resale benefit that it expected would be applied against its 2006 fuel budget, it proposed:

> For every dollar that NSPI's resale gas margin reduces NSPI's 2006 actual fuel expense below the allowed fuel expense in the approved rates pursuant to the filing before the Board, NSPI will, at the direction of the UARB, either refund such amounts to its customers or reduce future revenue requirements.
>
> (Exhibit N-187, p. 5)

[175] NSPI's Fuel Panel resumed its testimony after the natural gas settlement was filed with the Board. In a Supplementary Opening Statement, Mark Sidebottom, NSPI's Director of Fuels, Energy and Risk Management, reported:

> The agreement covers the full term of the contract. It will give NSPI and its customers greater certainty in future years. As a result of the favourable negotiating outcome, we have reduced our fuel expense for 2006 by $22 million. This works out on average to an approximate two percentage point reduction in our rate request, from an average of 15 percent to 13 percent overall. That said, the precise value of the contract still depends on natural gas prices, and gas production levels.
>
> The negotiations surrounding the natural gas contract involved a substantial amount of effort using both internal and external resources. This result is good for our customers.
>
> ...
>
> With respect to the natural gas agreement, NSPI recognizes the possibility this contract may result in a greater value than $22 million improvement in fuel expense.
>
> The company proposes that any additional savings from this contract above and beyond the fuel budget ultimately set in rates, should be provided to customers as a refund or a credit.
>
> This is consistent with our position that our intention is to recover our actual fuel expense, no more and no less.
>
> (Exhibit N-188)

[176] In cross-examination by John P. Merrick, Q.C., the Consumer Advocate, NSPI's Policy Panel elaborated upon the mechanism NSPI suggests be adopted to account for any additional benefits achieved under the new contract (i.e., over the level of

the $22 million improvement to the original fuel costs estimated by NSPI), and how it would be applied if there was a finding of imprudence by the Board:

> Q. (Merrick) Is it the position of the company that if there is any surplus revenue from gas sales over and above the **[confidential forecast margin]** that was identified in the supplemental hearing then it will not be used to offset or reimburse the company for any deduction that might be made for imprudence?
>
> A. (Huskilson) I think I can state the proposal that the company has made, and I think that is consistent with the proposal. And that is that we have said that gas revenues margin are to be set at the additional 22 million dollars ($22,000,000) which I think is **[confidential forecast margin]**, I believe, million dollars now, and that any value that we received over and above that number would be deducted from the approved amount for fuel expense that was approved by this Board and as long as we had costs below that. That's what we proposed, and that's what we continue to propose.
>
> Q. And would that include costs that you might incur but not be allowed to recover in rates because of an imprudence deduction?
>
> A. (Tedesco) If the fuel expense, just to pick some numbers, were set out, say, 500 million dollars ($500,000,000) and there was, for the sake of discussion, a ten million dollar ($10,000,000) disallowance, then the fuel budget would be set at four hundred and ninety million dollars ($490,000,000). The gas, again, sake of discussion, say added twenty million dollars ($20,000,000) of value to customers, so that would then lower the fuel budget then would be set at four hundred and seventy million dollars ($470,000,000). To the extent we came in below 470 million dollars ($470,000,000), then yes, the benefit of the gas contract would accrue to customers. To the extent we came in above 470 million dollars ($470,000,000), then no, it would not.
>
> Q. When you say "we came in," it would be your total expenses coming in below that number.
>
> A. (Tedesco) That's correct.
>
> Q. Including expenses that, for rate setting purposes, might have been deducted for imprudence -- a penalty for imprudence.
>
> A. (Tedesco) Correct.
>
> Q. So that the short answer to my question is that if there were deduction for imprudence, the company would still look to apply gas revenue against that before it would turn anything back in.
>
> A. (Tedesco) Yes, if we came in below. And I think the idea here would be there are bad things, there are good things. We think the gas contract is a good thing. It is not unreasonable that one, under those circumstances, should offset the other. Otherwise, we're simply playing a one-sided game.
>
> (Transcript, December 1, 2005, pp. 3202-3204)

[177] The Policy Panel provided further insight on this issue in response to questions from Board Counsel:

Q. And you then had a discussion with Mr. Merrick about the company's proposal for dealing with the gas resale benefits in excess of **[confidential forecast margin]**?
A. (Huskilson) Yes, sir, we did.

Q. You recall that. And to be certain that I understand the answers you gave to Mr. Merrick on that question, I want to put a simple hypothetical to you. And I emphasize that it's a hypothetical. Assume for the sake of argument only that the Board were to make an imprudence disallowance of ten million dollars ($10,000,000) on fuel in this proceeding. Now assume also that your fuel cost projections for 2006, except for the gas resale benefit, prove to be spot on. In other words, all your other fuel assumptions are correct. Thirdly, assume that the gas resale benefit in 2006 actually turns out to be **[confidential forecast margin plus $10 million]**, which is precisely ten million higher than the base estimate of **[confidential forecast margin]**, which you've asked to be built into the fuel budget. Now, in those circumstances, under the company's proposal, would any of the ten million dollars ($10,000,000) in extra gas resale benefits flow to customers or would it all go to the company?
A. (Tedesco) In the hypothetical that you've described, the way that ten million dollars ($10,000,000) would flow would be to pay the company's fuel costs, and that would be no different than our fuel budget today. So for instance, as already exists in our budget, as we've demonstrated in an earlier undertaking, coal is slightly below forecast, HFO is slightly above forecast. There is no argument that the cost of HFO – I haven't heard anyone say, "Well we should adjust the company's fuel budget upward nine or ten million dollars because of the cost of HFO." What we are saying is that the proposal that we've put forward is precisely consistent with how the Board has set rates in the past. The strip that we have used for gas is our assumption that was the gas price assumption presented in our filing. Based on that filing, we have estimated benefit of the gas contract of **[an additional]** twenty-two million dollars ($22,000,000). If it turns out it's less, that's at the company's risk. If it turns out it's more, that's at the company's benefit. In either case, the customer is not harmed once the fuel budget is set.

Q. Mr. Tedesco, I understood all of those parts. I just wanted to be sure, under the company's proposal, what happened to that ten million dollars ($10,000,000).
A. (Tedesco) You've characterized it correctly.

...

Q. In other words, the upshot is -- and I realize that it can be characterized a number of ways, and I'm not disagreeing with what Mr. Tedesco has said -- but the effect of it is, in this hypothetical which I posed, the company would recover its full fuel budget including the ten million dollars ($10,000,000) that was found to be imprudent prior to any gas resale benefits flowing to customers. That's the bottom line.
A. (Tedesco) Well, it's -- I wouldn't characterize it that way.

Q. I realize you wouldn't ---
A. (Tedesco) It's really ---

Q. --- but that's what would happen. Nothing would go to customers until the amount -- the excess exceeded ten million.
A. (Tedesco) That's right. But it would be no different than the risk that we take on today. There is nothing to say that fuel -- that gas prices will change in such a way that we may end up under-recovering. There is nothing to say that the gas deliveries -- as I said earlier, we believe we have a very aggressive assumption on gas deliveries. There is nothing to say that those deliveries will not show up. These are risks that the company takes on, and as I said last night, what we're -- really all we're asking for is we'll take the good with the bad. We don't want to be punished for doing something good.

(Transcript, December 2, 2005, pp. 3282-3286)

[178] In its application filed July 5, 2005, NSPI's projection for the gas resale margin was based on the May 2005 forward price strip for natural gas. Following the announcement of its settlement, NSPI updated its estimate of the anticipated resale margin that may be achieved under the settlement. At the request of Board Counsel, NSPI provided an update using the May 2005 forward price strip (increasing the benefit by $22.6 million) and using the November 2005 forward price strip (increasing the benefit by $64.1 million).[43]

[179] In the testimony of Dr. Stutz, discussed in greater detail below, he proposed setting up a reserve fund, equal to any excess of the actual gas resale margins for 2006 (above the amount included in rates), to be distributed to the benefit of the Company and its customers following consideration, in a future rate hearing, of results achieved during the 2006 test year.

[180] NSPI submits that Dr. Stutz's proposal imposes all the risk of future natural gas price fluctuations upon the Company. In cross-examination, the Policy Panel

[43] Supplemental Stutz IR-8 (updated November 25, 2005) and Undertaking U-58 (filed December 6, 2005)

expressed the following concerns about his proposed reserve fund, and its future distribution:

A. (Tedesco) Dr. Stutz's proposal is different from ours.

Q. (Merrick)Would you have any objection to Dr. Stutz's proposal?
A. (Tedesco) Yes, I would.

Q. And what would be the basis of your objection?
A. (Tedesco) Again, the company is simply looking to recover its fuel costs, both good and bad, and whatever they may be and wherever they may be set, to the extent we beat that target, then we would agree those costs should accrue to customers. It's not fundamentally different, in my mind, than some of the proposals that have been put forth during the hearing by some to say, well, we should reduce the fuel budget, certain [coal] contracts are below forecast, while ignoring that certain other oil contracts are above forecast.

A. (Huskilson) And I think, Mr. Merrick, I think it would be important to say that the proposal that the company has made is very similar to the circumstance that it finds itself in today or has found itself in the past. And so we would see that that proposal is not changing the circumstance the company has always had, whereas the proposal -- this proposal looks like it does change those circumstances. And so that's why we would take issue with it.

A. (Tedesco) I think we need to be very conscious of we're in an environment with volatile fuel costs. We find ourselves today in a circumstance in part because of imprudence, in part because of dramatically higher fuel costs where we have, indeed, a bow wave. To continue to scoop or seek to scoop only the good and ignore the bad I think only builds that bow wave for future years.

(Transcript, December 1, 2005, pp. 3206-3207)

[181] The Policy Panel reiterated these concerns in cross-examination by Board counsel:

Q. (Outhouse) ...You have said, as I understood Mr. Huskilson to say yesterday to the Board, be very careful how you price that gas under the contract because if ... you set that margin too high, then it could come back to haunt us if we don't realize that margin, and the company could be seriously harmed, as I understood you, Mr. Huskilson.
A. (Huskilson) That's exactly right. And so the proposal that we have made allows the company to have some protection around that issue, but also allows some opportunity for customers to see the benefit of that. And so we thought that that was balanced. If the proposal that Dr. Stutz was making was a two-sided proposal, one that would say, "We're going to set up an account for the gas contract" and pluses or minuses would be flowed through, that would be a different kind of arrangement

which would be more aligned to the kind of suggestion the company has made. And that would be a different arrangement that might make more sense.

...

Q. Dr. Stutz's proposal does not create any down-side risk on the gas contract for the company.
A. (Huskilson) Yes, it does.

Q. How?
A. (Huskilson) Because the **[confidential forecast margin]** is not assured.

Q. No. But that's the company's proposal too.
A. (Huskilson) I understand.

Q. So his proposal doesn't add to that risk.
A. (Huskilson) No, it doesn't add to that risk, but it takes another risk component -- or adds another risk component to the company, which is the overall fuel situation. And that increases the risk. So the company was willing to take the risk that the **[confidential forecast margin]** was a good number based on the fact that there was a balance on the other side.

Q. Mr. Tedesco?
A. (Tedesco) It would certainly be our hope and position that this issue be moot. And I say that from the perspective of we do not believe there has been imprudence. If indeed there is no imprudence, there is no issue with the company's proposal, and any benefits will accrue 100 percent to customers.

(Transcript, December 2, 2005, pp. 3290-3296)

[182] Another aspect of the settlement of issues surrounding NSPI's natural gas agreement is its impact upon the long-term receivable. The existing agreement includes a price adjustment clause respecting natural gas purchases over a period of three years. Under the clause, the Company pays for the natural gas purchases at an agreed upon contract price, but at the end of three years is entitled to receive a rebate based on the application of a price cap. The savings achieved as a result of the price cap are reflected in the long-term receivable, which has been estimated by NSPI. The Company submits

that, if the Board decides to increase the natural gas resale benefit, then there should also be a corresponding adjustment in the long-term receivable.

3.7.2 Submissions - Dr. Stutz and Intervenors

Dr. Stutz

[183] In his testimony, Dr. Stutz proposed a different mechanism for the treatment of the natural gas resale benefit, if it ultimately exceeds NSPI's post-settlement estimate of the benefit:

> Finally, let me turn to the Gas Resale Margin. Recent developments discussed in the confidential portion of these hearings have led NSPI to increase the benefit from the gas resale included in its proposed test year required revenues. The Company has also proposed that, to the extent that additional gas resale margins reduce NSPI's actual total fuel expense below the amount approved by the Board for inclusion in rates, the difference will, following Board direction, be applied to benefit ratepayers.
>
> The Company's revised estimate of gas resale benefits reflects the uncertainty in the amount of gas it may sell and the margin it will earn per unit volume sold. It would be reasonable to assume that the Company has taken care not to overestimate the revised benefits included in its base rates. It is also reasonable to assume that actual gas resale margins may exceed those that the Company proposes to include in its required revenues. Thus, the treatment of additional gas margin revenues could be important.
>
> The Company's proposal for the treatment of additional gas margin revenues does not permit the Board to decide now how the benefit of such revenues would be divided between the Company and its customers. To provide the Board the opportunity to make that decision, I recommend that the Board direct the Company to set up a reserve fund equal to the excess, if any, of actual gas resale margins for 2006 above the amount included in rates. The Board need not decide how the fund will be used now, nor whether the fund will benefit NSPI, its customers, or both. That can be decided in the general rate proceeding to be held in 2006 or at whatever time the Board finds it appropriate.
>
> (Stutz Opening Statement, Exhibit N-244; Transcript, December 2, 2005, pp. 3514-3515)

Avon

[184] Avon raises three issues with respect to the incorporation of natural gas costs and resale benefits into NSPI's fuel budget for the 2006 test year. First, it asks the Board to review the settlement between NSPI and its natural gas supplier to ensure that the benefits arising under the settlement are allocated fairly between the Company's shareholders and ratepayers. Avon notes that the settlement addressed two issues, namely, compensation to NSPI relating to deliveries of natural gas prior to December 16, 2005, and the establishment of a price and supply arrangements respecting future deliveries of natural gas. The latter would benefit NSPI's customers, while the former would accrue to the benefit of the shareholders. Avon cautions that the negotiation of both items in one settlement raises issues about whether NSPI received additional compensation respecting deliveries of natural gas prior to December 16, 2005, at the expense of terms related to future pricing of natural gas under the contract.[44]

[185] In cross-examination by Robert G. Grant, Q.C., Counsel for Avon, Mr. Tedesco acknowledged that there was a relationship between the settlement of issues respecting both past and future deliveries of gas:

> ... I would characterize that [compensation for deliveries prior to December 16, 2005] as absolutely instrumental to receiving the assurances that we did for [future] gas deliveries.
>
> (Transcript, November 24, 2005, p. 1585)

[186] Second, Avon also expressed concern about the reasonableness of NSPI's revised forecast for the natural gas resale margin under the negotiated settlement. While

[44]Avon, **Confidential** Closing Submission, pp. 14-16

Avon acknowledges that the forecast based on the November forward price strip may be too optimistic, it stated that NSPI's revised forecast based on the May 11, 2005 forward price strip was unreasonably low. In light of these two extremes, Avon suggested that the Board establish an amount for anticipated gas revenues "based on its realistic view of the current gas markets".[45]

[187] Finally, Avon described NSPI's proposed refund or deferral account as "illusory" because any surplus would first be used to offset deficiencies for other fuel types in NSPI's fuel budget, including the imprudence disallowance, before customers would benefit from any improved gas margin.[46] In Avon's view, such a mechanism detracts from the punitive nature of an imprudence disallowance.

[188] However, Avon did express support for deferring any surplus gas resale margin, stating that any such excess ought to accrue to the benefit of customers either by way of a refund or a reduction of future revenue requirements.[47]

Consumer Advocate

[189] The Consumer Advocate highlighted the two suggested methods for dealing with the anticipated natural gas resale benefit. In his Closing Submission, the Consumer Advocate suggested that one approach would have the Board factor the natural gas resale benefit into NSPI's fuel budget, for the purpose of setting rates. Applying this approach,

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[45] Avon, Redacted Closing Submission, p. 18

[46] Avon, Redacted Closing Submission, p. 13

[47] Avon, Redacted Closing Submission, p. 18

the Consumer Advocate noted that the risk/benefit would lie with the Company's shareholders, as it should be under rate-setting principles. However, the Consumer Advocate submitted that if this method is to be adopted for the purpose of setting rates, then the Board should revise upward the gas resale benefit estimated by NSPI since, in his view, it is clearly too low.

[190] In the alternative, the Consumer Advocate concurs with Dr. Stutz's suggestion that a reserve fund be set up to capture any gas resale benefit to the extent it exceeds NSPI's revised estimate. The Consumer Advocate opposes NSPI's suggestion that any surplus benefit from the resale of natural gas should be applied against other fuel costs, including an imprudence finding. Such risks, in the opinion of the Consumer Advocate, should properly be borne by the Company's shareholders.[48]

Province

[191] In its Closing Submission, the Province reiterated its qualified support for a fuel adjustment mechanism, noting that the development of a FAM should be undertaken carefully and with stakeholder involvement in its design and implementation. The Province suggested that steps should be taken towards the implementation of a FAM once NSPI has hired an in-house coal expert and made its procurement decision-making process more transparent.[49]

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[48]Consumer Advocate, Redacted Closing Submission, pp. 7-8

[49]Province, Redacted Closing Submissions, pp. 21-22

[192] With respect to NSPI's suggested mechanism for dealing with any excess natural gas resale benefit, the Province suggests that a better approach is for the Board to incorporate the anticipated revenues from gas resales into the Company's total fuel budget, using the best information available to the Board with respect to the likely pricing of natural gas in the 2006 test year. The Province is reluctant to adopt the mechanism proposed by NSPI because, in its view, the natural gas resale benefit to be realized is likely to exceed that projected by NSPI, given the most up-to-date forward price strip available to the Board at the conclusion of the hearing. The Province observes that the difference could be approximately $40 million if the November 2005 forward price strip (rather than the May 2005 forward price strip) accurately predicts the state of the natural gas market in the test year. In that event, the Province notes that ratepayers would be making a considerable prepayment against future rates, or possible rebate, something which current ratepayers facing a proposed double digit increase should not be asked to absorb.[50]

CME

[193] The CME opposes NSPI's proposal to offset any surplus natural gas resale benefit against a shortfall in its overall fuel budget and against any imprudence disallowance. In its Closing Submission, the CME challenges NSPI's proposed assignment of risks between NSPI and its customers with respect to the fuel budget:

> 41. The present lack of a fuel clause is not relevant and it is worthy of note that until fuel procurement has achieved a level of sophistication in design and execution satisfactory to NSPI, the Board and ratepayers a fuel clause or fuel adjustment mechanism (FAM) is unlikely to be implemented because it has to be a proper balancing of the risk.

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[50] Province, Redacted Closing Submissions, pp. 19-21

> 42. Also, it is the position of the CME that risk should not be **symmetrical** as indicated by Mr. Tedesco. NSPI receives a good rate of return. Encapsulated in that rate of return is a premium for risk. It has in the past, and should be in the future, be responsible for the operations of the business and the risks that go with it including fuel procurement. It is the beneficiary of a known rate of return (notwithstanding an imposed limited). The relationship of risk is not symmetrical. The impetus for ratepayers approving a FAM or such other mechanism is for the benefit of predictability, leveling of fluctuations and in some cases, sharing of risk but it is not one of symmetry. Any acceptance under a FAM or such other mechanism is based on the good operations of such a mechanism. Any other shift would remove the incentive from the operator.[Emphasis added in original]
>
> (CME, Redacted Closing Submission, p. 23)

SEB

[194] SEB also opposed the mechanism proposed by NSPI. In its Confidential Fuel Related Argument, SEB submitted that NSPI's gas resale benefit should be set based on the November 2005 forward price strip filed in Undertaking U-58. SEB stated that NSPI's forecast for the gas resale benefit (based on the May 2005 forward price strip) is not reasonable because there is more current information filed with the Board. SEB argued that it would be unreasonable to allow NSPI to apply any surplus gas resale benefit to offset increases in its remaining fuel budget, describing as patently unreasonable NSPI's suggestion that any such surplus gas resale benefit should also be used to offset an imprudence disallowance.[51]

[195] SEB reiterated its position that customers should get the immediate benefit of the gas resale margin, rather than deferring the benefit to a future test year:

> In its Closing Argument NSPI attempts to paint the picture of deferring the potential value of the gas contract as a good thing, so as to possibly alleviate the burden of a future rate increase. As NSPI's two largest customers, SEB have no interests nor do they think it is appropriate to delay, a potential benefit so as to alleviate future rate increases. This is

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[51] SEB, **Confidential** Fuel Related Argument, pp. 50-51

> particularly so in the face of the extraordinary increase proposed for SEB by NSPI in this proceeding. SEB's position is that customers should get the full benefit of the natural gas resale margin, and that this should be done by way of application of the current third party available indices.
>
> (SEB, **Confidential** Fuel Related Rebuttal Argument, p. 17)

[196] SEB encouraged the Board to ensure that it is satisfied with the accounting treatment of the natural gas contract and the long-term receivable contained in NSPI's evidence. Further, SEB expressed concern that, following the announcement of the natural gas settlement, Undertaking U-76 showed a greater long-term receivable at the end of 2005 than the amount shown in Appendix A of the original filing, implying that 2005 purchased gas costs were overstated compared to the contractual cap. SEB suggested that this demonstrates an unfair allocation of the settlement to shareholders and that the overstatement should be available to customers of NSPI as a refund.[52]

3.7.3 Findings

[197] As a result of the settlement reached between NSPI and its natural gas supplier, the Company expects to achieve better results on the resale of its natural gas than originally forecast when it filed its application on July 5, 2005.

[198] There are various issues which arise with respect to the natural gas component of the fuel budget, including: 1) what price should be attributed to the commodity and what volume can NSPI expect to receive, in order to determine what

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[52]SEB, **Confidential** Fuel Related Argument, p. 53

natural gas resale benefit should be incorporated into NSPI's total fuel budget; 2) whether the Board should approve a deferral mechanism as proposed by NSPI or, alternatively, a reserve fund, as proposed by Dr. Stutz; 3) whether the benefits of the natural gas settlement were appropriately allocated between NSPI's shareholders and customers; and 4) whether the long-term receivable should be adjusted to reflect the Board's findings respecting the gas resale benefit.

[199] The first issue requires the Board to determine the amount of the natural gas resale benefit to be incorporated into NSPI's total fuel budget.

[200] Based on its review of the record, the Board is satisfied that NSPI's estimated impact of the settlement (increasing the benefit by $22.6 million) is too conservative, while the revised estimate based on the November 2005 forward price strip (increasing the benefit by $64.1 million) is too optimistic. Having regard to the highly volatile nature of the natural gas market, and the potentially significant impact that this amount can have on NSPI's fuel budget, the Board recognizes that caution is required. Nevertheless, weighing the relevant evidence, virtually all of which is confidential, the Board finds that it is reasonable to adopt a gas resale benefit $35.8 million higher than that contained in the original filing of July 5, 2005, thereby decreasing NSPI's original fuel budget by the same amount. The Board notes that this results in a gas resale benefit for 2006 which is very comparable to the gas resale benefit actually realized by NSPI in each of 2004 and 2005. The Board sees nothing in the material produced at the hearing which would indicate that NSPI will not be able to achieve at least an equal gas resale benefit in 2006.

[201] The determination of the natural gas resale benefit impacts upon the Board's consideration of the deferral mechanism proposed by NSPI and the reserve fund suggested by Dr. Stutz.

[202] While the Board recognizes that NSPI's proposed deferral mechanism is not, strictly speaking, a fuel adjustment mechanism ("FAM"), its effect is similar, in some respects, in terms of its potential impact upon NSPI's proposed fuel budget.

[203] Following the Board's review of the evidence and submissions, it considers that there are various issues which detract from the approval of a deferral mechanism or reserve fund at this time.

[204] In its March 31, 2005 decision, the Board refused to incorporate a FAM proposed by NSPI:

> [131] The Board shares the views of the intervenors with respect to the FAM proposed by NSPI. The Board recognizes that FAMs exist in many other jurisdictions and can, potentially, be a positive and useful regulatory tool. However, in view of the Board's findings with respect to imprudence and inadequacies in NSPI's fuel procurement practices, it would be quite inappropriate to approve a FAM at this time. The Board does not believe it is in the public interest to transfer the risk of fuel price volatility to ratepayers when NSPI's ability to achieve the best possible fuel price is in question.
>
> [132] Further, the Board is of the view that transferring such risk from shareholders to ratepayers could diminish the incentive for NSPI to quickly and thoroughly improve its fuel procurement process. This is particularly the case since the FAM proposed by NSPI would transfer 100% of the risk to ratepayers. Accordingly, the Board rejects the proposed FAM. Further, in view of the Board's concerns in this area, should NSPI apply for approval of a FAM in future, the Board will order an independent audit of NSPI's overall progress and performance with respect to the necessary fuel procurement improvements. This audit would include, as recommended by Liberty, "... a more detailed examination..." of fuel and energy transactions and relationships with affiliates and would form part of the evidence the Board would consider in any future FAM application.
>
> (Board Decision, March 31, 2005, para. 131-132)

[205] While the Board has concluded in this decision that NSPI has made significant improvements in its fuel procurement procedures, the Board still has reservations about incorporating, at this time, an adjustment mechanism with respect to NSPI's fuel budget. As noted above, there remain elements of the Company's Fuel Procurement Policies and Procedures Manual which require improvement, most notably as it relates to natural gas, and improving the transparency of its decision-making in relation to its fuel. In these circumstances, the Board is reluctant to vary from its current regulatory practice of setting the fuel budget.

[206] There are further reasons for the Board's conclusion. First, Dr. Stutz's proposal contemplates an adjustment mechanism which is limited to variances in one type of fuel, rather than the range of fuel types comprising NSPI's portfolio. In the view of the Board, any such adjustment mechanism, if adopted, should apply to all fuel types collectively. Further, NSPI's proposal would allow it to recover any shortfall in its overall fuel budget, including imprudency. In the opinion of the Board, this is not an equitable proposal for customers in that they would not likewise benefit if NSPI were to achieve better results than the fuel budget approved by the Board. In other words, NSPI's shareholders would be afforded the opportunity to offset any costs above the approved budget for 2006, while customers would not be entitled to benefit if the Company was able to achieve better results in its remaining fuel budget than currently forecast. Moreover, setting the natural gas resale benefit at the level proposed by NSPI, accompanied by either the deferral mechanism proposed by NSPI or the reserve fund proposed by Dr. Stutz,

would, in the opinion of the Board, provide little incentive to NSPI to improve upon the forecasted benefit.

[207] Furthermore, and most importantly, in a test year where customers are facing a significant rate increase, the Board is loath to defer any potential benefits from the gas resale benefit to a future test year.

[208] Accordingly, the Board concludes that the gas resale benefit should be increased by $35.8 million above that contained in NSPI's original application dated July 5, 2005, and that no deferral mechanism or reserve fund should be implemented at this time.

[209] Avon and SEB asked the Board to consider whether the benefits of the natural gas settlement between NSPI and its supplier were appropriately allocated between the Company's customers and shareholders. As noted by Avon in its Redacted Closing Submission, the settlement addressed two issues, namely, compensation to be received by NSPI for deliveries of natural gas from its supplier prior to December 16, 2005, and the establishment of a price and improved supply arrangements respecting future deliveries of natural gas, but only to the extent that gas is available to the supplier. Customers will benefit from a fair price and improved supply arrangements for future deliveries which likely will be resold into the market with the revenue applied against NSPI's fuel budget. On the other hand, shareholders will benefit from compensation for deliveries of natural gas from the supplier prior to December 16, 2005.

[210] As noted previously, the settlement between NSPI and its supplier was reached in the midst of the hearing. The terms of the settlement were filed in a confidential exhibit. The Board concurs with Avon and SEB that NSPI must satisfy the Board that the benefits of the settlement were fairly allocated between the customers and shareholders.

[211] The Board observes that the dispute between NSPI and its natural gas supplier involved complex contractual issues. The two parties were both sophisticated entities, each of which thought that their respective positions were sufficiently strong to lead them to pursue a ruling from an independent arbitration panel. Subsequent to the arbitration, but before the arbitration decision was issued, the parties reached their agreement.

[212] In commercial disputes like the one under consideration, there is never any guarantee of success. A claim may be denied by the court or tribunal, or decided in a manner not anticipated by either party to the dispute. Both NSPI and its supplier no doubt made some compromises in reaching the terms of settlement.

[213] The Board is satisfied from its review that the settlement clearly involved the two issues identified by Avon. While the shareholders of NSPI benefitted from a lump sum payment, representing compensation for deliveries of natural gas from the supplier prior to December 16, 2005, the settlement also benefitted customers because NSPI negotiated terms with respect to the supply arrangements and price of natural gas for future deliveries. This will benefit NSPI customers in 2006 and beyond because it provides greater certainty with respect to price and volume. In the absence of this negotiated settlement, it is not

possible to determine with any certainty whether NSPI would have been successful on either of these two points at arbitration.

[214] It is difficult to ascertain whether the benefits from the settlement were scrupulously allocated between the shareholders and the customers of NSPI. However, the Board is satisfied that the issues relating to deliveries of natural gas prior to December 16, 2005 and the fixing of future prices and supply arrangements were inextricably related to one another such that it would not have been practical or reasonable to reach a settlement between the parties without addressing both issues concurrently. The Board is satisfied that NSPI, to the extent possible, attempted to segregate those issues in its negotiations with the supplier. It is very possible that an arbitration decision respecting issues of pricing and volume for future gas deliveries could have been less favourable for NSPI customers than that achieved under the negotiated settlement.

[215] Having reviewed the terms of the negotiated settlement, the testimony related to it, and the submissions of the parties, the Board is persuaded that the settlement reached with the supplier benefits NSPI's customers and that there was a fair and reasonable allocation of the benefits accruing under the settlement between shareholders and customers.

[216] In its Compliance Filing, NSPI should address the Province's concerns with respect to the long-term receivable, as set out in paragraph 68 of its Closing Submission.

3.8 Fuel Costs

3.8.1 Submissions - NSPI

[217] The primary issue is the accuracy of NSPI's original fuel forecast. NSPI, in calculating the cost to be ascribed to coal required for the test year but not purchased at the time of the application, based its value on the forecast prepared by Hill & Associates. A number of the intervenors took the position that it would have been more appropriate to price the uncommitted coal using EVA's forecast, which was generally lower than Hill's. In the eyes of the intervenors at least, the EVA forecast was also more accurate, since it correctly predicted the downward trend in coal prices which subsequently occurred.

[218] With respect to the forecasts, NSPI argued that it has been difficult to forecast fuel prices with any degree of accuracy in the past few years. In this regard, NSPI emphasized that there was no evidence in the 2005 rate case predicting either the magnitude or the duration of the price spike which occurred.[53]

[219] NSPI continued:

> Nevertheless, in the current case, intervenor consultants now purport to see the global coal market clearly and have concluded that it is falling. They hold strong opinions on what price forecast NSPI should use and which one it should not use. This certainty about 2006 is less impressive, when one is reminded of the collective failure of these consultants to predict the magnitude and duration of the market price event that started in late 2003 and has continued to this date.
>
> . . .
>
> Certain intervenors asked why NSPI did not use the lowest possible forecast price available to estimate its balance of the year prices. The answer is simple. The EVA forecast was not offered as an alternative to Hill. In fact, until February 2005, EVA had not published a forecast of South American coal in its FUELCAST/COALCAST Service. EVA recommended that NSPI use the Hill forecast because Hill & Associates has an international reputation with respect

[53] Exhibit N-153, pp. 11-12

to South American coal. It publishes multiple multi-client reports on this coal region including the annual forecast report upon which NSPI relied.

(Exhibit N-153, p. 11)

[220] NSPI stated that:

... Now that the coal market price is below the budget amount, several of the intervenors would like an adjustment to all uncommitted tonnes at the time of the Application. This is similar to a request in the 2004 Application that NSPI adjust its foreign exchange requirements for un-purchased coal due to the strengthening of the Canadian dollar. As with coal, NSPI has policies regarding currency hedging. The Board did not accept this recommendation, which suggests a recognition that that the continued hedging was appropriate and an ex post facto adjustment related to the decline in the foreign exchange was inappropriate for committed hedges. The same philosophy is appropriate with respect to solid fuel hedges.

(Exhibit N-153, p. 15)

[221] In its Closing Argument, NSPI submitted:

It has been the practice of the Board to set rates based upon the forecasts as filed, provided they are reasonable. The evidence demonstrates that NSPI used reasonable forecasts, professionally prepared by experts in the field. Prices for committed and uncommitted fuel in the NSPI application are accurate and proper for rate-making purposes.

Nova Scotia Power has relied upon a forecaster with an international reputation. No other party to the proceeding offered an alternative forecast that provided comparable data with sufficient documentation so as to be a suitable substitute for the Hill forecast.
. . .

The evidence shows that the overall fuel costs anticipated by NSPI for 2006 are appropriate, even in light of volatile fuel markets. As indicated in NSPI's response to U- 29, changes in the cost of one fuel are just as likely to be offset by changes in the cost of another. ...

(NSPI, Redacted Closing Argument, pp. 18-19)

[222] In its Reply to Closing Argument, NSPI maintained that the overall fuel budget, as filed, represents a realistic number, notwithstanding that parts of the forecast may be higher or lower than the proposed budget:

The fuel budget contained in NSPI's 2006 application is based upon the best information available at the time of the application, in accordance with the ratemaking principles of this jurisdiction. No Intervenor offered into evidence an alternative price forecast which contained any detail or applicability to be useful to the Board. Ms. Medine completely explained that the

> EVA forecast of quarterly spot prices is not an appropriate forecast for NSPI's 2006 fuel costs. The evidence confirmed that parts of NSPI's forecast may be higher or lower than the budget but overall represent a realistic number.
>
> Further, NSPI customers are protected from over recovery in two ways. First, NSPI is capped with respect to earnings should fuel costs come in lower than expected. Second, NSPI customers could receive a refund if natural gas revenues are higher than forecast subject to NSPI recovering its fuel costs.
>
> (NSPI, Redacted Reply to Closing Argument, p. 7)

3.8.2 Submissions - Intervenors and Liberty

SEB

[223] In its Final Confidential Fuel Related Argument, SEB submitted that:

> ... NSPI's fuel forecast should be adjusted to take account of the fact that NSPI is utilizing a very high forecast for 2006 imported ... coal tonnage which was not committed at the date of the application. NSPI utilized the March 2005 Hill & Associates Forecast notwithstanding that it was substantially higher than the forecast for 2006 available to NSPI from its consultants EVA.
>
> (SEB, Final **Confidential** Fuel Related Argument, p. 38)

[224] Mr. Gubbins adjusted the balance of the uncommitted coal, to reflect the difference in the price forecast prepared by Hill & Associates as compared with the forecast prepared by Mr. Gubbins' firm, McCloskey Group. Mr. Gubbins stated that the Hill price forecast for 2006 was too high. The adjustment calculated by Mr. Gubbins is $9.45 million.

[225] According to SEB, it is clear from the record that the current prices for coal support the use of a lower forecast. As an example, SEB quoted from Mr. Gubbins' opening statement in which he suggested that prices on November 11, 2005, as reported

in the McCloskey Coal Report, were significantly lower than the prices used by NSPI in its forecast.[54]

AVON

[226] Avon, in its Closing Submission, contended that the use of the Hill forecast was inappropriate. This is because the prices forecast by Hill were too high and thus overstated the fuel requirements for 2006.

[227] Avon argued that the Hill forecasts are demonstrably wrong, and "... fail to reflect the cyclicality in the international coal market which all experts agree exists,. . . and this Board should be wary about using long-term forecasts for near term coal commitments. Certainly, even NSPI's consultants Ms. Medine and Daniel Walton, agreed that shorter term forecasts are more accurate than long as a general rule."[55]

[228] Should the Board agree that the Hill long-term forecasts are inappropriate to use for the test year, then Avon suggested that there are several options which the Board could use. One option is for the Board to take the uncommitted volume as of the date that NSPI filed its rate case and substitute a more representative cost estimate based on either the EVA forecast, as Dr. Raschke did, or the McCloskey forecast, as Mr. Gubbins did. The impact of using the EVA forecast, according to Dr. Raschke, would be to reduce the fuel

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[54]SEB, Final **Confidential** Fuel Related Argument, p. 39

[55]Avon, Redacted Closing Submission, pp. 8-10

budget by approximately $28.2 million. Using the McCloskey forecast reduces costs by about $10 million.[56]

[229] Avon also indicated that:

> The Board may account for commitments made since the rate filing and replace the balance of the uncommitted tonnages and options with the appropriate "plug" number - whether EVA forecast or McCloskey. Undertaking U - 29 sets out NSPI's most current volumes, replacing its forecasted figures with committed prices...
>
> (Avon, Redacted Closing Submission, p.11)

[230] In its Closing Submission, Avon presented a calculation prepared by Dr. Raschke which, according to Avon, demonstrates that "... even if all of NSPI's current contracts are accepted the coal costs claimed for 2006 are still too high by at least $14.8 million..."[57]

[231] Avon maintained that "It would be inappropriate for NSPI to have the benefit of a unreasonably high cost per MMBtu when it is based on a demonstrably wrong long-term forecast and when its own contracts subsequently entered into show this."[58]

[232] In its Reply Submission, Avon revised its proposed adjustment to the fuel costs from the $14.8 million figure previously recommended to a recalculated figure of $21.3 million. Avon stated:

> At our request, Dr. Raschke reviewed the transcripts of the NSPI fuel panel and using the information regarding the current contracts and their options, recalculated the savings to NSPI from its contracts entered into since May 1, 2005, assuming the negative exercise of

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[56] Avon, Redacted Closing Submission, pp. 10-11

[57] Avon, **Confidential** Closing Submission, pp. 11-12

[58] Avon, **Confidential** Closing Submission, pp. 11-12

> the contract options. The recalculated figure is $21,277,636 versus his previous assessment of $14,768,533. His revised calculations are appended as Appendix "A".
>
> NSPI's fuel budget is not reasonable; it is unrepresentative and the forecasted coal cost number is demonstrably wrong. Avon respectfully submits that the Board ought to disallow $21.3 million from NSPI's 2006 fuel budget based on the fact that NSPI has entered into lower priced contracts replacing its uncommitted volumes forecasted at higher levels. If the fuel budget is approved as stated, it would offer a windfall to NSPI shareholders, who would benefit from the fact that contracts have been committed at lower prices.
>
> (Avon, Redacted Reply Submission, p. 6)

Province

[233] The Province, in its Closing Submission, took no position concerning whether NSPI's original fuel price forecasts were appropriate. However, it stated that the fuel budget should be revised because it no longer accurately reflected the 2006 fuel costs likely to be incurred.[59]

[234] The Province pointed out that a number of circumstances, which have occurred since the original test year estimates were prepared, cause the original projections to be less relevant to the 2006 test year. These events include savings achieved on coal contracts entered into since the application was filed, at prices less than original forecast, and HFO prices which have increased over those originally forecast by NSPI. The Province noted that:

> ... Liberty has taken the position that the gains that NSPI is likely to realize in improvements to its solid fuel forecasts will be offset by the likely higher HFO prices. In Liberty's view, these factors amount to a wash, though no specific calculations were provided to support that opinion.
>
> (Province, **Confidential** Closing Submission, pp. 17-18)

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[59] Province Redacted Closing Submission, p. 15

[235] The Province made no specific recommendation with respect to this issue.

Liberty

[236] Liberty stated, in its Direct Evidence, that NSPI's estimate of solid fuel costs for the 2006 test year "... has turned out to be too high, as recent NSPI purchases have reduced the amount of uncommited tonnages and at prices less than NSPI had estimated."[60]

[237] In its pre-filed evidence, Liberty concluded that there should be a reduction of $10,378,294 in fuel expense for the 2006 test year, because NSPI... "has been able to secure at lower than estimated prices much of the fuel that was uncommitted at the time of the Company's filing."[61] Liberty explained that these reduced costs related to low sulphur coal and petcoke.

[238] In its opening statement at the hearing,[62] Liberty indicated that it was no longer recommending the reduction in question. Liberty stated that, because the net effect of price changes in heavy fuel oil (HFO), petcoke and coal, when the currently uncommitted fuel is eventually acquired, is uncertain and cannot be quantified at this time, it believes that the change should be treated as a wash. During cross-examination, Mr. Grant asked Liberty to confirm that "... you are comfortable with the concept that whatever savings will be made on the remaining uncommitted solid fuel, that will be offset by

[60] Exhibit N-97, p. 8

[61] Exhibit N-97, p. 11

[62] Exhibit N-214

increases in prices in HFO over budget". Liberty replied that "... We're comfortable that the net of the changes on all solid fuel and HFO would be an offset to current budget."[63]

3.8.3 Findings

[239] The Board observes that Undertaking U-29, filed by NSPI on November 28, 2005, provided an estimate of the effects of commitments to date in HFO, coal, and petcoke, as compared with the forecast in the original filing. Undertaking U-29 indicated that reductions in cost were realized on the coal and petcoke commitments entered into since the application was filed, while increases were experienced in the cost of HFO. As a result of these changes, NSPI asserted its total fuel cost has increased from the $478.9 million reflected in the filing, to $481.7 million, an increase of $2.8 million to November 28, 2005, the date of the Undertaking.

[240] After considering the evidence in relation to this matter, including the issue of volume options, the Board is not persuaded that there should be any adjustment to the

[63] Transcript, November 29, 2005, p. 2338

coal, petcoke, and HFO portions of the fuel budget, and agrees with Liberty's recommendation in this respect.

[241] Accordingly, the Board sets NSPI's fuel budget for the test year as follows:

Total Estimated Fuel Costs as per original filing	$478,900,000
Less Additional Natural Gas Resale Benefit determined by Board	(35,800,000)
Less PTMT Disallowance	(2,300,000)
Less Imprudence Disallowance	(15,700,000)
Approved Fuel Budget	$425,100,000

4.0 FINANCE

4.1 Return on Equity

[242] The capital to finance NSPI's generating, transmission, distribution and other assets comes from equity investors, as well as through the issuance of debt. The return on equity (the "ROE") earned by the Company represents the income earned by the equity investors. In the 2005 rate decision, the Board approved an ROE at 9.55% for the purpose of setting rates, with an earnings range set at 9.30% to 9.80%. While NSPI contends that this ROE is very close to that granted elsewhere in Canada for utilities which do not face comparable fuel and generation risks borne by the Company, NSPI is not proposing any change with respect to ROE in the present case, considering the recent decision by the Board on this issue.

[243] The proposed ROE was not the subject of comment by any of the intervenors at the hearing. While the NDP Caucus raised the issue of an appropriate ROE in its Closing Submission, there was no evidence to support a change in the ROE.

4.1.1 Findings

[244] The Board is satisfied that the ROE should be maintained at 9.55% for the purpose of setting rates, with the earnings range set at 9.30% to 9.80%.

4.2 Capital Structure

[245] In the 2005 rate decision, the Board also approved an increase in the common equity ratio for ratemaking purposes from 35% to 37.5%. This increase, which was supported by a majority of the intervenors in the 2005 rate case, was considered desirable by the Board to strengthen the Company's balance sheet in the current economic climate and also reflective of Emera's common equity ratio. For the 2006 test year, NSPI proposes that the common equity ratio for ratemaking purposes continue at 37.5%. The proposed common equity ratio was not the subject of comment by any of the intervenors at the hearing.

4.2.1 Findings

[246] The Board is satisfied that the common equity ratio for ratemaking purposes should be maintained at 37.5%.

5.0 RATE BASE

5.1 Overview

[247] In the 2005 rate decision, the Board noted a consensus among the intervenors that NSPI should change the way it calculates the rate of return to a return on rate base methodology. Accordingly, the Board approved a change to NSPI's long-standing practice of calculating its return on the equity portion of total capitalization and directed that NSPI use a return on rate base methodology for its next rate application. The Board further directed NSPI to file in its next rate application all information and explanations necessary to enable the Board and intervenors to clearly understand the basis of NSPI's calculations. The Board noted that NSPI should also reconcile its calculations of return on rate base to calculations using the return on equity methodology.

[248] The main issue which arose from the adoption of the rate base methodology was calculating the cash working capital ("CWC") allowance. Kathleen C. McShane, Senior Vice-President of Foster Associates, Inc., filed evidence and testified at the hearing on behalf of NSPI with respect to the determination of the CWC allowance. In NSPI's Rebuttal Evidence, she defined CWC allowance and how it is typically determined:

> The cash working capital allowance reflects the average amount of capital provided by investors above and beyond investments in plant and other separately identified rate base items, including other components of working capital (e.g., materials and inventory), that bridges the gap between the time expenditures are made to provide service and the time payment is received for that service. The rate base in its entirety represents the amount of investor-supplied capital required to provide service; the cash working capital component needs to be compatible with the determination of the other elements of the rate base.
>
> The cash working capital allowance is typically measured using a lead/lag study. The purpose of a lead/lag study is to provide a measure of the amount of investor funds used in sustaining utility operations from the time expenditures are made until the time payment is received.

> A lead/lag study recognizes that the utility renders service prior to receipt of payment from ratepayers, but that there is generally also a delay in payment for goods and services acquired by the utility. The lead/lag study analyzes transactions throughout the year to determine the net lag days between the date service is rendered and payment is received (revenue lag), and the time lag between the time expenditures are recorded and payment is made for such expenditures (expense or payment lag). In some instances, revenue may be received prior to payment for the related expense. In that case, there will be a net lead (or alternatively, a negative net lag).
>
> (NSPI, Rebuttal Evidence, Exhibit N-153, pp. 58-59)

[249] NSPI projects that it will require $29.4 million to be included in the rate base for CWC allowance in the 2006 test year.[64]

[250] Ms. McShane described NSPI's methodology of determining its CWC allowance as an approach focusing on the operating or "above-the-line" expenses of NSPI. She states that this approach excludes non-cash expenses (e.g., depreciation) and return on capital.[65]

[251] Several intervenors have raised issues with the calculation of the CWC allowance. Specifically, they have questioned NSPI's exclusion of items like HST, securitized accounts receivable, interest expense and preferred dividends. They have also challenged some of the lead/lag assumptions made by NSPI. Further, at least one intervenor has questioned NSPI's reconciliation of its return on capitalization versus its return on rate base, as it believes the result should be the same in each case. These issues are examined, in turn, below.

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[64]NSPI Application, Exhibit N-2, Appendix A, Table 17

[65]NSPI Rebuttal Evidence, Exhibit N-153, p. 61

5.2 HST

5.2.1 Submissions - NSPI

[252] In its original application, NSPI did not include HST in its calculation of the allowance for CWC.[66]

[253] In his testimony, Greg Blunden, NSPI's General Manager of Finance, indicated that the Company's approach was to include only operating expenses and that it excluded items like HST and payroll taxes that may flow through their accounts. Stating that there are only a couple of days difference between the collection and remitting of HST, it was felt that the exclusion of HST would have no material impact upon the CWC requirement.[67]

[254] During questioning by Board counsel, Mr. Blunden was asked to calculate the impact of the HST upon CWC. In its response to Undertaking U-35, NSPI calculated the "possible impact" of the timing difference between the collection and remittance of net HST, concluding that it could reduce the cash operating working capital by $4.4 million for the 2006 test year. Multiplying this amount by the weighted average cost of capital (i.e., 8.21%), the total revenue requirement would be reduced by $400,000.[68]

[255] In its Closing Argument, NSPI confirmed that the revenue requirement would be reduced by $400,000 if the CWC were to be adjusted for the collection and remittance

[66]Exhibit N-2, Appendix A, Table 17

[67]Transcript, November 22, 2005, p. 1010

[68]NSPI, Undertaking U-35, Attachment 1

of HST. However, it added that if the rate base is to be adjusted in this fashion, then other adjustments to the rate base should also be made for items like the 2005 Q1 tax deferral and the increase in the long-term receivable.[69]

5.2.2 Submissions - Intervenors

[256] In his Direct Evidence, Mark Drazen, who appeared on behalf of Avon, submitted that HST should be included in the determination of CWC allowance.

[257] On the assumption that HST must be remitted within 30 days following the end of the month in which it is collected, Mr. Drazen determined that NSPI had use of the money for 45 days on average (15 days in the month of collection plus 30 days thereafter) or 12.3% of the year. Based on the net HST remitted in the amount of $75.7 million,[70] Mr. Drazen determined that the CWC allowance would be reduced by $9.3 million ($75.7 million x 12.3%).[71]

[258] While Avon acknowledged, in its Closing Submission, that Ms. McShane was not involved in NSPI's initial calculation of the CWC allowance, it noted that she did not identify HST for inclusion in the lead/lag study in her rebuttal testimony filed on behalf of NSPI.[72]

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[69] NSPI, Redacted Closing Argument, p. 77

[70] Identified by NSPI in response to Avon IR-54, Attachment 1

[71] Drazen, Pre-filed Evidence, Exhibit N-95, p. 9

[72] Avon, Redacted Closing Submission, para. 131-133; McShane, Rebuttal Evidence, Exhibit N-153, p. 58

[259] Mr. Grant cross-examined Ms. McShane on the inclusion of HST during the hearing, challenging her on this issue relative to her pre-filed evidence in a recent Hydro Quebec rate hearing in which she identified HST as an appropriate item for inclusion in the CWC allowance. However, it was not identified in NSPI's application.[73] Further, she acknowledged that Newfoundland and Labrador Hydro, a client on whose behalf she testified during their 2001 rate application, included HST in its lead/lag study, reducing the CWC requirement for that utility.[74] She also agreed HST is typically included in lead/lag studies.[75]

5.2.3 Findings

[260] Based on its consideration of this matter, it appears that the issue to be determined by the Board relates to the extent of the HST's impact upon the CWC allowance, rather than a question of its exclusion from the CWC. While HST was not originally included by NSPI in the determination of its CWC requirement, it appears from the testimony of Mr. Blunden that its exclusion was related to the belief that it would not have a material impact upon the determination of the CWC requirement.[76]

[261] The Board concurs with Mr. Drazen that HST should be included in the determination of the CWC requirement. Inherent in this finding is a recognition that the

[73] Hydro Quebec Pre-filed Evidence, Exhibit N-173, p. 6; Transcript, November 22, 2005, p. 970

[74] Exhibit N-174, pp.4-5; Transcript, November 22, 2005, p. 973

[75] Transcript, November 22, 2005, p. 967

[76] Transcript, November 22, 2005, p. 1010

Company does have use of the money between the time it is collected from customers and the time it is ultimately remitted to government. This treatment of the HST also appears consistent with the treatment afforded to HST in other jurisdictions such as Quebec and Newfoundland and Labrador, as acknowledged by Ms. McShane in cross-examination.[77] Further, the Board notes Ms. McShane's testimony relating to Hydro Quebec to the effect that Hydro Quebec's methodology to determine cash working capital focuses on operating or "above-the-line" expenses.[78]

[262] Moving beyond the threshold of determining that HST is appropriately included in the CWC allowance, NSPI and Avon differ upon the magnitude of its impact. Using information provided by NSPI in response to Avon IR-54, Attachment 1, Mr. Drazen calculated the reduction of CWC allowance as being $9.3 million. NSPI, on the other hand, calculated the reduction of the CWC allowance as only $4.4 million, resulting in a reduction of the revenue requirement by $400,000.[79] The Board observes that NSPI did not cross-examine Mr. Drazen during the hearing with respect to his calculation of the HST's impact upon the CWC allowance. According to Mr. Blunden, the distinction between the two methodologies focuses on the revenue lag, i.e., Mr. Drazen assumed the HST is not remitted until after it is collected from customers, while NSPI undertook its analysis on the basis that HST remittances are triggered based on when customers are invoiced.[80]

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[77]Transcript, November 22, 2005, p. 967

[78]Hydro Quebec Pre-filed Evidence, Exhibit N-173, p. 7

[79]NSPI Undertaking U-35

[80]Transcript, November 22, 2005, pp. 1009-1010; see also Avon IR-54

[263] Upon reviewing this matter, the Board notes that NSPI, in calculating the working capital impact of including an adjustment for the HST, based its calculations on the model employed by Newfoundland and Labrador Hydro. The model employed by NSPI calculates the payment lag for each type of the expenditures on which NSPI pays HST, as well as for the customer billing on which NSPI collects HST. The Board believes this is a realistic manner of calculating the HST impact on CWC and, accordingly, accepts NSPI's calculation of $400,000 as a reduction in the 2006 revenue requirement.

5.3 Interest Expense and Preferred Dividends

5.3.1 Submissions - NSPI

[264] On behalf of NSPI, Ms. McShane stated that interest expense and preferred dividends should not be included in the determination of CWC allowance. In her view, the determination of CWC should focus on operating or "above-the-line" expenses of NSPI, to the exclusion of non-cash expenses (e.g., depreciation) and operating income (i.e., return on capital). She submitted that any lead/lag study which includes interest expense must also include all sources of investor supplied funds, such as allowances for depreciation expense and return on equity. She stated that incorporating interest expense and preferred dividend payments into the CWC requires the adoption of a broad or "global" approach to measuring the full extent to which investors finance the revenue requirement of the Company. In such instances, she argued that leads and lags on all elements of the return of, and on, capital must be taken into account. In her submission, the inclusion of

interest and preferred dividend payments, to the exclusion of depreciation expense and common equity return, is equivalent to "cherry-picking", which results in an understatement of the actual CWC requirement.[81]

[265] In support of her position, Ms. McShane relies, in part, on the rejection of the "global" approach by other regulators in Canada, including the Régie de l'Énergie du Québec. She cites two of its decisions:

> In D-99-11 (Gaz Metro), the Régie concluded,
>
> > Following the analysis of the evidence submitted, the Régie is of the opinion that only the operating costs should be taken into account in the calculation of the working capital. According to the Régie, the global approach over-estimates the requirements by considering not only the cash flows related to the distribution service but by also taking into account the return on equity and retained earnings which advantages the shareholders. A lead-lag study, according to the global methodology, would increase significantly the cash working capital, without, however, assuring that such a result would accurately reflect reality. The Régie considers that it is preferable to limit the lead-lag study analysis to only the income statement items directly related to the service itself. Moreover, the Régie notes that few rulings have been issued on this subject up until now.
>
> In D-2001-55 (Gazifère), the Régie stated,
>
> > the Régie, in its decision, takes account of the conclusion of Bonbright to the effect that any method produces approximate results and that the objective is to determine an amount which is reasonable, without a degree of refinement that causes the costs to be higher than the associated benefits:
> >
> > > 'None of the methods for calculating the working capital allowance will produce a result that is precisely correct. The purpose of the calculation should be to arrive at an amount that is reasonable and contains no obvious defects, and which is not so time-consuming to compute that the cost exceeds the benefit.'
> >
> > The Régie accepts the distributor's demonstration that the depreciation expense is a valid element of the global method. Depreciation does not generate a cash expenditure; however, the recovery of the depreciation expense is delayed for the period of the revenue lag. Meanwhile, the

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[81] McShane Pre-filed Evidence, NSPI Rebuttal Evidence, Exhibit N-153, p. 61

> investors continue to provide the funds for a certain portion of the depreciation expense.
>
> With regard to the inclusion of interest expense and dividends proposed by OC/ACEF, the Régie considers that these payments are made from funds that belong to the investors and arise from the manner of financing, which is taken into account in the capital structure. If one were to consider that the delay in the payment of interest and dividends constitutes a source of funds, it is also necessary, according to the Régie, to consider all of the other elements of the capital structure and thus ultimately to examine whether the global method is well-founded.
>
> The Régie considers that it would not be fair to order Gazifère to use the global method. This method introduces, according to the Régie, certain complexities that have not been fully studied.
>
> The Régie is of opinion that the evidence submitted is insufficient to justify such a fundamental change in the methodology used to calculate working capital. The current methodology having the advantage of having been tested, it is up to the intervenor OC/ACEF to demonstrate, in a convincing way, that the current method is no longer appropriate. In the opinion of the Régie, this demonstration was not made. The Régie considers that it would not be appropriate to adopt the methodology suggested by OC/ACEF.
>
> (NSPI Rebuttal Evidence, Exhibit N-153, pp.67-69)

[266] Ms. McShane noted that adoption of the “global” approach in NSPI’s case would increase its CWC requirement, primarily because the equity return is earned by common equity investors when the service is provided, but the collection of the return is delayed until payment is received from ratepayers (i.e., the net lag on the equity return would be equivalent to the revenue lag resulting from the collection of NSPI’s billings, which the Company states is 42 days).

[267] Ms. McShane testified that the Alberta Energy and Utilities Board has been using the “global” approach in the calculation of CWC allowance since 1988. Adopting NSPI’s figures with respect to revenue and expense lags, Ms. McShane estimated that

using the “global” approach would increase NSPI’s CWC allowance by as much as $13 million over its present estimate of $29.4 million.

[268] In cross-examination by Mr. Grant, Ms. McShane agreed that in the case of Newfoundland and Labrador Hydro, the utility adjusted its interest expense downward to account for the timing of payments on bonds.[82]

5.3.2 Submissions - Intervenors

[269] Both Mr. Drazen and James T. Selecky, of Brubaker & Associates, Inc., contend that interest expense and the payment of preferred dividends should be taken into account in the calculation of CWC allowance. They each noted that the Company collects revenues from its customer billings throughout the year, but the payments of interest occur as late as semi-annually, in the case of long-term bonds, and quarterly, in the case of preferred dividend payments. In both cases, they note that NSPI collects its revenues in advance of the time it is required to pay the interest and preferred dividends. Thus, in their view, these funds represent a source of working capital which should be taken into account in reducing the CWC requirement.[83]

[270] Mr. Drazen, when challenged on his methodology in cross-examination by René Gallant, Counsel for NSPI, noted that other utilities like Fortis BC and Centra Manitoba include interest expense and preferred dividend payments in their calculation of

[82]Transcript, November 22, 2005, pp. 977-979

[83]Drazen Pre-filed Evidence, Exhibit N-95, pp. 9-10; Selecky Pre-filed Evidence, Exhibit N-91, pp. 4-5

the CWC, to the exclusion of other elements such as depreciation and common equity return. He added that Ms. McShane identified these two utilities, in her pre-filed evidence, as adopting this methodology. Mr. Drazen also noted that in hearings involving Newfoundland and Labrador Hydro, the regulator approved a practice which takes into account the recovery of revenues from customers to pay interest, thereby reducing the cost of the utility's debt. While he acknowledged that this methodology is different than what he suggests, the final result, he stated, is exactly the same as that calculated using his proposed methodology.[84]

5.3.3 Findings

[271] With respect to this issue, NSPI submits that interest expense and the payment of preferred dividends should not be taken into account in the calculation of CWC allowance. Alternatively, in the event that the Board finds that these expense items should be included, Ms. McShane asserts that such a finding would require the Board to adopt the "global" approach, taking into account depreciation expense, as well as return on common equity. To do otherwise, she suggests, amounts to "cherry-picking" the items which will be included in the calculation.

[272] For Mr. Drazen and Mr. Selecky, the issue simply comes down to the fact that NSPI collects its revenue from customers before it is required to pay interest expense and

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[84]Transcript, December 1, 2005, pp. 3189-3190

preferred dividend payments. In their view, NSPI's use of these funds in the intervening period effectively reduces its CWC requirement.

[273] In their submissions, Avon and SEB both submit that interest expense and preferred dividend payments should be taken into account in the determination of CWC allowance, but not depreciation expense or common equity return. Avon highlighted the distinction between these expenses as follows:

> 147. It is submitted that the global approach advocated by Ms. McShane does not accurately measure the Company's need for utilization of cash which is the function of the allowance for CWC. Depreciation is not a cash obligation of the company. For the payment of dividends on common equity there is a discretion on the part of the company with respect to the time and amount. Payments of preferred dividends, by contrast, are cash payments, the time and amount of which are subject to terms agreed to by investors. Similarly, interest payment upon debt is a cash payment required in accordance with the terms agreed to between the company and the holders of its debt.
>
> (Avon, Redacted Closing Submission, p. 32)

[274] While maintaining that the inclusion of interest expense and preferred dividend payments should not be considered without adopting the "global" approach, Ms. McShane acknowledged on cross-examination by George T.H. Cooper, Q.C., Counsel for SEB, that there is a distinction between these and other expenses included in the "global" approach, in that depreciation expense is not a cash obligation and that the payment of common equity return is subject to the discretion of the Company in terms of the timing and amount of dividends paid on common shares. Further, she acknowledged that revenue

collected by NSPI for payment of interest expense and preferred dividend payments do contribute to the cash NSPI has available to it to earn a return.[85]

[275] The Board has considered the evidence of Mr. Drazen and Mr. Selecky that interest expense and preferred dividends should be taken into account in calculating the CWC. The Board understands the reasons why they argue in favour of their inclusion in the CWC calculations. However, the Board notes that other regulators have considered this matter, and have disagreed with the inclusion of interest and preferred dividends in the calculation of CWC.

[276] Ms. McShane, in NSPI's Rebuttal Evidence of November 7, 2005, quoted from a National Energy Board decision of August 1986, which dealt with this matter:

> With regard to the payment of interest on long-term debt and preferred share dividends, the Board is of the opinion that these items, which are not a function of operations but of the financing of the Company, are components of the rate of return. Furthermore, they relate to contractual obligations entered into between Westcoast's shareholders and the Company's other investors. As such, they do not involve the day-to-day operations of the Company, and do not properly belong in the calculation of the cash working capital allowance. (National Energy Board, Reasons for Decision, Westcoast Transmission Company Limited, August 1986)
>
> (Exhibit N-153, p. 70)

[277] The NEB, in its decision, was dealing with whether interest expenses and preferred dividends ought to be included in the calculation of the cash working capital allowance. It states that cash working capital allowance is intended to measure the cash requirement for the day-to-day operations of the Company. The NEB was of the view that interest on long-term debt and preferred share dividends are not a function of the day-to-

[85] Transcript, November 22, 2005, pp. 931-935

day operations, and thus do not belong in the calculation of cash working capital. Rather, they are a function of the financing of the Company, and thus are components of the rate of return. In addition, according to the NEB, these items relate to contractual obligations entered into between the Company's shareholders and other investors.

[278] Ms. McShane, in Exhibit N-153, also set out the views of the Régie de l'Energie du Québec, as contained in two cases concerning the same matter. The views of the Régie can be summed up with the following quote:

> With regard to the inclusion of interest expense and dividends proposed by OC/ACEF, the Regie considers that these payments are made from funds that belong to the investors and arise from the manner of financing, which is taken into account in the capital structure. If one were to consider that the delay in the payment of interest and dividends constitutes a source of funds, it is also necessary, according to the Régie, to consider all of the other elements of the capital structure and thus ultimately to examine whether the global method is well-founded.
>
> The Régie considers that it would not be fair to order Gazifère to use the global method. This method introduces, according to the Régie, certain complexities that have not been fully studied.
>
> (Exhibit N-153, pp. 68-69)

[279] Ms. McShane makes the case that if the interest on long-term debt and the preferred dividends are to be included in the calculation of the CWC, then the calculation must also include depreciation expense and return on equity:

> ... If the cash working capital allowance is to be interpreted in the broad or "global" sense of measuring the full extent to which investors have financed the revenue requirement, leads and lags on all elements of the return of and on capital must be taken into account. Inclusion of interest payments alone, to the exclusion of depreciation expense and common equity return, amounts to "cherry-picking", and will understate the cash working capital requirement....
>
> (Exhibit N-153, p. 61)

[280] According to Ms. McShane, were the CWC calculations to include depreciation and all return on capital items, there would be an increase in the CWC of $6.60 million, rather than a decrease as proposed by Mr. Drazen and Mr. Selecky.

[281] Based on the evidence, the Board is not persuaded that the methods advocated by Mr. Drazen and Mr. Selecky should be adopted for purposes of calculating CWC in this rate case. The Board agrees with the observation of the Régie that "... this method introduces ... certain complexities that have not been fully studied." For the Board to move in that direction, a more detailed consideration of the "global" approach would be required. Accordingly, the Board accepts the recommendation of Ms. McShane concerning this matter.

[282] At a future rate hearing, should additional evidence be presented concerning the "global" approach and the inclusion of interest expenses and preferred dividends in the calculation of CWC, the Board would be willing to reconsider the matter.

5.4 Securitization of Accounts Receivable

5.4.1 Submissions - NSPI

[283] NSPI maintains that the funds received from its accounts receivable securitization program should not be taken into account in determining the Company's CWC allowance.

[284] Under this program, NSPI sells a "co-ownership interest" in a portion of its accounts receivable to a trust. The trust, in turn, pledges its co-ownership interest as

security in order to obtain funds from investors, which the trust lends to NSPI. NSPI pays securitization fees to the trust in an amount equivalent to interest charges on a conventional short-term loan (i.e., $2.4 million for the 2006 test year[86]). The trust pays a portion of the securitization fees back to the investors, who are ultimately repaid their original loan by NSPI, through the trust.

[285] Accounting rules allow the securitization transaction to be treated as a sale of receivables. For reporting purposes, the affected accounts receivable are removed from the balance sheet, along with the associated short-term debt, which is paid from the proceeds of the accounts receivable transferred to the trust.[87]

[286] Ms. McShane submits that customers of NSPI benefit in two ways from this arrangement. First, by reducing the amount of capital on NSPI's balance sheet, the Company reduces its liability for Large Corporation Tax. This tax saving is reflected in the revenue requirement and passed along to NSPI's customers. Second, the securitization allows NSPI to lower the costs of its short-term financing, because the security for the loan is comprised of relatively liquid assets.[88] The Board infers that the reduced costs of the short-term financing results in lower interest expenses for NSPI.

[287] In Ms. McShane's opinion, the securitization is substantively the same as using accounts receivable as collateral for a short-term credit facility. In obtaining short-term financing in this fashion, she maintains that NSPI has not reduced its revenue lag

[86]NSPI Application, Exhibit N-2, Appendix A, Table 10

[87]NSPI, Rebuttal Evidence, Exhibit N-153, p. 79

[88]McShane, Pre-filed Evidence, NSPI Rebuttal Evidence, Exhibit N-153, p. 73

and, thus, not reduced its CWC allowance. In her view, the fundamental difficulty with the intervenors' suggestion that the securitization reduces the CWC allowance is described as follows:

> To claim that the accounts receivable securitization program reduces NSPI's revenue lag is tantamount to claiming that any utility whose short-term credit facilities are secured by accounts receivable has reduced its revenue lag. Utilities require short-term debt because there is a lag between rendering service and receiving payment. The short-term debt is the investor-financing that bridges the gap. It is a circular argument to then claim that because the utility has obtained the short-term debt to bridge the gap, the lag between provision of service and receipt of revenues has been reduced. To claim that the revenue lag is reduced by the securitization program (thus reducing the cash working capital requirement), is equivalent to claiming that NSPI does not need the short-term debt, a clearly erroneous conclusion.
>
> (NSPI, Rebuttal Evidence, Exhibit N-153, p. 73)

[288] During its testimony at the hearing, the Finance Panel reiterated NSPI's position that the funds obtained from the securitization program should not be included in the CWC allowance. Ms. Zeda Redden, NSPI's General Manager, Finance, testified that the program merely replaces the debt owed to one group of investors (i.e., short-term debt holders) with new debt owed to the trust. Thus, in her view, the transaction does not affect CWC. She added that NSPI still retains all of the risk with respect to the collection of the accounts receivable which have been securitized. Further, she noted that financial institutions such as banks and rating agencies consider the securitization to be outstanding debt, which is taken into account in conducting their credit assessments.[89]

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[89]Transcript, November 22, 2005, pp. 936-937; NSPI Rebuttal Evidence, Exhibit N-153, p. 80

5.4.2 Submissions - Intervenors

[289] Both Mr. Drazen and Mr. Selecky are of the view that the securitization program should be taken into account in the calculation of NSPI's CWC requirement. Both witnesses noted in their Direct Evidence that NSPI expects to securitize about $53.75 million of accounts receivable per month,[90] representing approximately 60% of its monthly revenues.[91] Further, they note that NSPI's customers are charged the projected annual cost of $2.4 million to implement the securitization program. This amount is imputed as interest expense and included in the Company's revenue requirement.

[290] Mr. Selecky suggests that the monies received from the securitization program effectively reduces NSPI's CWC requirement:

> ... the securitization of the receivables provides the Company with cash that reduces its short-term debt. Therefore, NSPI has cash available quicker than it otherwise would. The availability of this cash reduces the revenue lag days utilized to calculate its cash working capital requirement.
>
> (Selecky Direct Evidence, Exhibit N-91, p. 7)

[291] Both Mr. Selecky and Mr. Drazen accounted for the impact of the securitization program by reducing the revenue lag to be used in the calculation of the CWC. Mr. Selecky estimated that NSPI would experience a 10 day lag in receiving the securitized funds, resulting in a weighted revenue lag of 22.8 days.[92] In the absence of information from NSPI with respect to the timing of receipt of monies from the securitization

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[90] SEB IR-213, Attachment 1

[91] Drazen Pre-filed Evidence, Exhibit N-95, p. 11; Selecky Pre-filed Evidence, Exhibit N-91, p. 7

[92] Selecky Pre-filed Evidence, Exhibit N-91, p. 8

program, Mr. Drazen assumed that the Company received the monies immediately upon request, resulting in an average revenue lag of 19.2 days.[93] Both Mr. Drazen and Mr. Selecky then incorporated the revised revenue lag into their calculation of the CWC allowance (see Appendix C).

[292] The Board observes that the significant decrease in the revenue lag calculated by both Mr. Drazen and Mr. Selecky effectively results in a negative CWC requirement, albeit in varying degrees because of the different assumptions made by both witnesses with respect to other expense lead/lag items discussed elsewhere. Mr. Drazen indicated that this caused him no concern since it is simply a reflection that the Company's cash flow is such that revenues are collected before the monies have to be paid out. He described this as "money in the bank", stating that it is a source of financing for the Company. He noted that other utilities have shown a negative CWC in their filings.[94]

[293] In cross-examination by Mr. Gallant, Mr. Drazen and Mr. Selecky each acknowledged that the securitization of accounts receivable by a company is different than the practice of "factoring" (i.e., the sale of) receivables. They agreed that the latter results in the creation of revenue from the sale of a future revenue stream, while securitization results in the creation of debt. They were also unable to identify any other jurisdiction where securitization, as opposed to "factoring", is approved by regulators.[95]

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[93]Drazen Pre-filed Evidence, Exhibit N-95, p.12

[94]Drazen Pre-filed Evidence, Exhibit N-95, p.13

[95]Transcript, December 1, 2005, pp. 3193-3194 (Drazen); Transcript, December 2, 2005, pp. 3319-3320 (Selecky)

5.4.3 Findings

[294] The Board has considered the respective submissions relating to the treatment to be afforded the securitization of accounts receivable in the determination of CWC allowance. In this regard, the Board reviewed the evidence of Ms. McShane, Mr. Drazen and Mr. Selecky, along with the submissions of the parties.

[295] The Board accepts the evidence of Ms. McShane that the securitization transaction is substantively similar in nature to a utility that pledges its accounts receivable as collateral to obtain a short-term credit facility. In effect, the transaction simply substitutes the debt owed by NSPI to one group (i.e., short-term bond holders) by debt owed to another group (i.e., the trust). Securitization is distinct from a sale or "factoring" of receivables because, under the securitization program, NSPI continues to bear the risk of ultimately collecting the accounts receivable and the short-term debt must be repaid. No debt is issued under 'factoring", which instead produces revenue from the sale of a future revenue stream. The Board concludes that the securitization program does not reduce NSPI's revenue lag and, accordingly, the transactions should have no impact on the CWC allowance requirement.

[296] The Board notes that the transactions benefit NSPI's customers through reduced Large Corporation Tax and also, the Board infers, through lower financing charges[96].

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[96]NSPI reports the securitization fees as deductions to Other Revenues (Exhibit N-2, Appendix A, Table 1

5.5 Other Lead/Lag Assumptions

5.5.1 Submissions - NSPI

[297] NSPI states in its application that this marks the first opportunity in some time for the Company to carry out a lead/lag study, noting that the amount of CWC was not relevant to the setting of rates based on the capitalization methodology previously applied by the Board. NSPI submits that it has undertaken a rigorous approach to the determination of CWC in this rate application.[97]

[298] The Company asserts that its lead/lag assumptions are reasonable, submitting that a CWC allowance of $29.4 million should be included in the rate base.

[299] Following the conclusion of the hearing, NSPI raised a further issue with respect to the calculation of the rate base, asserting that during the course of the hearing it became apparent, in NSPI's view, that the 2006 rate base is understated by $30.0 million due to the exclusion of the 2005 Q1 tax deferral and the potential increase of the long-term receivable associated with the gas contract achieved as a result of the November 16, 2005 settlement. It submits that if the rate base is to be adjusted as requested by the intervenors, then adjustments to the 2005 Q1 tax deferral and the long-term receivable must also be taken into account, increasing the revenue requirement by approximately $2.0 million.[98]

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[97]NSPI Rebuttal Evidence, Exhibit N-153, p. 83

[98]NSPI Redacted Closing Argument, p. 71 and p. 77

5.5.2 Submissions - Intervenors

[300] In evidence filed on behalf of Avon, Mr. Drazen challenges some of the lead/lag assumptions made by NSPI in the determination of its CWC requirement. A table showing a summary of Mr. Drazen's conclusions respecting lead/lag assumptions, along with those of NSPI and Mr. Selecky, is contained in Appendix C to this decision. His determination of NSPI's CWC requirement for the 2006 test year is negative $54.8 million. Using the same methodology to calculate the 2005 CWC requirement, he averaged the two figures at negative $51.1 million, compared to NSPI's claimed average of positive $29.4 million.

[301] In addition to Mr. Drazen's inclusion of the HST, the securitization of accounts receivable, as well as interest and preferred dividends in the calculation of the CWC, which have already been discussed, part of the difference is accounted for by differing lead/lag assumptions. In his Direct Evidence, Mr. Drazen indicated that NSPI shows a longer revenue lag and shorter expense lags than it did in the 2005 rate case. He notes that these two factors combine to increase the net lag in recovery, resulting in a larger CWC requirement.[99] NSPI's lag assumptions for the 2005 and 2006 rate case, along with the estimates of Mr. Drazen and Mr. Selecky for the 2006 test year, are contained in the following Table which was compiled by the Board[100]:

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[99]Drazen Pre-filed Evidence, Exhibit N-95, pp. 7-8

[100]Drazen Pre-filed Evidence, Exhibit N-95, p. 7 and p. 13

PROPOSED REVENUE AND EXPENSE LAGS				
	2005 Rate Case	2006 Rate Case	Drazen 2006	Selecky 2006
Revenue - monthly	31.0 days	36.0 days	-	-
- bi-monthly	53.0	53.0	-	-
Weighted Average	42.0	42.0	38.9 days	42.0
Labour	21.0	15.0	21.0	15.0
Non-labour operating	50.0	45.0	50.0	45.0
Fuel & purchased power	29.4	30.4	29.5	30.0
Grants in lieu of taxes	**	(91.0)	(91.0)	(91.0)
Income taxes	**	30.0	53.0	30.0
** Not included in study				

[302] Backing out the impact of the securitization program, which the Board has concluded should not be taken into account in determinating the CWC allowance, Mr. Drazen's projected revenue lag should be adjusted to 38.9 days, rather than the 19.2 days contained in his Direct Evidence. In support of this conclusion respecting 38.9 days, Mr. Drazen noted that NSPI revised its 50/50 split of monthly and bi-monthly billings (which produces an average lag of 42 days) to a 64/36[101] split (which produces a weighted average of 38.9 days).[102]

[303] Further, in Mr. Drazen's opinion, NSPI has not explained the reasons for reducing most of the expense lags from those suggested by NSPI in the 2005 rate case, noting that the expense lag relating to fuel and purchased power is the only expense lag

[101]NSPI Application, Exhibit N-2, Appendix A, Table 17, lines 15-26

[102]Drazen Pre-filed Evidence, Exhibit N-95, p. 11

which has increased, albeit by a marginal amount. He recommends that the expense lags remain at the 2005 levels.

[304] With respect to NSPI's inclusion of income taxes and grants in lieu of taxes in the CWC calculation, Mr. Drazen stated that this is consistent with his recommendation during the last Rate hearing. He also noted that the average expense lag of negative 91 days for grants in lieu of taxes is virtually identical to the number recommended by him in last year's rate case. However, with respect to income taxes, Mr. Drazen asserts that the average lag should be 53 days rather than the 30 days estimated by NSPI. In support of this submission, Mr. Drazen refers to Avon IR-48(f), Attachment 1, in the 2005 rate case, which outlined that 83% of income taxes are paid monthly, with the balance of 17% being paid the following February. While he acknowledges that the ultimate amount paid depends on the Company's performance, he states that an iterative process is required to determine the actual amount to be paid for income taxes.[103]

[305] Mr. Drazen also suggests that other sources of working capital may include a reserve for bad debts and the amortization of deferred financing charges (defeasance costs). However, he indicated that NSPI had not provided sufficient information to assess these two other potential sources of working capital.[104]

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[103]Drazen Pre-filed Evidence, Exhibit N-95, p. 8

[104]Drazen Pre-filed Evidence, Exhibit N-95, p. 14

[306] In support of his assertion that NSPI's stated rate base is overstated, Mr. Drazen compiled an analysis of NSPI's rate base, comparing the amounts shown in the 2005 and 2006 rate applications.

[307] With respect to the revenue lag, Mr. Selecky adopted the 42 day lag estimated by NSPI and deducted therefrom a number of days to account for the securitization program, resulting in a weighted revenue lag of 22.8 days. Given the Board's exclusion of the securitization program from the determination of CWC, the Board observes that Mr. Selecky agreed, at least implicitly, with NSPI's 42 day revenue lag.

5.5.3 Findings

[308] The 2006 test year marks the first time that the determination of CWC allowance is relevant to the setting of rates. Prior to this point, CWC was not a factor in establishing rates under the capitalization methodology. However, it is a component of the rate base approach to be followed in this application.

[309] The Board is mindful of Mr. Drazen's observation that, compared to other rate base items, CWC is one of the most difficult to determine because it is not tied to a specific expenditure.[105] As noted by Mr. Blunden in his testimony, the determination of CWC is merely intended to serve as a proxy for actual working capital, which fluctuates throughout the year. He stated that, with the exception of CWC, all other items in the rate base can

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[105] Drazen Pre-filed Evidence, Exhibit N-95, p. 5

be traced back to the Company's external audited financial statements.[106] Against this backdrop, the Board considers it important that this topic be broached with some caution.

[310] Four issues arise from the evidence and the submissions with respect to the lead/lag assumptions for the determination of the CWC allowance: 1) the determination of the appropriate revenue lag (42 days versus 38.9 days); 2) the appropriate expense lag for income taxes (30 days versus 53 days); 3) whether the other expense lags should be set at the levels estimated by NSPI during the 2005 rate case[107] or at the new estimated levels; and 4) whether other potential sources of CWC should be considered.

[311] Removing the impact of the securitization program upon the revenue lag, Mr. Drazen calculated 38.9 days for the revenue lag, compared to the 42 days adopted by NSPI and, without discussion of the point, by Mr. Selecky. Mr. Drazen used information provided by NSPI to calculate a weighted average of 38.9 days. He noted that the Company confirmed, during last year's rate hearing, that the correct split between monthly and bi-monthly billings was 50/50, yielding an average lag of 42 days. However, in the present rate application, NSPI revised the monthly/bi-monthly split to 64/36,[108] but maintained the 42 day lag. Mr. Drazen indicated that this revised split reduces the weighted average from 42 days to 38.9 days.

[312] NSPI provided no evidence to explain why revising its split of monthly and bi-monthly billings from 50/50 to 64/36 would not alter the weighted average of 42 days, nor

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[106] Transcript, November 22, 2005, pp. 946-947

[107] Undertaking U-34 (2005 Rate application SEB IR-222)

[108] NSPI Application, Exhibit N-2, Table 17, lines 15-26

did it cross-examine Mr. Drazen on his calculation. Accordingly, the Board accepts Mr. Drazen's calculation of the revenue lag as being 38.9 days.

[313] Similarly, Mr. Drazen referred to Avon IR-48(f), Attachment 1, in the 2005 rate case, in determining that the average lag for income taxes should be 53 days rather than the 30 days estimated by NSPI. That IR response noted that 83% of income taxes are paid monthly, with the balance of 17% being paid the following February. He acknowledged that the ultimate amount paid for income taxes depends on the Company's performance and more information would be required to determine the actual timing for the payment of income taxes. NSPI did not provide any evidence during this application to revise its answer to last year's response to Avon IR-48(f) (even though Mr. Drazen made specific reference to it in his pre-filed evidence), nor did counsel for NSPI cross-examine Mr. Drazen on the point. In the absence of further evidence on this issue, the Board accepts Mr. Drazen's evidence that the expense lag with respect to income taxes should be 53 days rather than 30 days.

[314] In the present application, NSPI has reduced the expense lags for labour, non-labour and fuel from those it provided during the 2005 rate case. Mr. Drazen indicates that the expense lags should remain as described by NSPI during the 2005 rate case until further information is provided. He states that the decreases in these expense lags were not explained by NSPI. The Board concurs with Mr. Drazen.

[315] Based on the above findings, the CWC requirement would be $12.25 million (averaged with 2005 F). The Board's conclusions with respect to the determination of NSPI's CWC allowance are summarized in the following Table:

SUMMARY OF BOARD FINDINGS 2006 Cash Working Capital Requirement (Dollars in Millions)					
Category	**Lag Days (a)**	**Net Lag Days (b) [38.9 days - (a)]**	**% of Year (c) [(b)/365]**	**Annual Cost (d)**	**CWC [(c) x (d)]**
Revenue lag	38.9				
Labour	21	17.9	4.90%	$119.3	5.85
Non-labour operating	50	(11.1)	(3.04)	90.5	(2.75)
Fuel & purchased power	29.4	9.5	2.60	479.0*	12.45
Grants in lieu of taxes	(91)	129.9	35.59	32.6	11.60
Income taxes	53	(14.1)	(3.86)	84.4	(3.26)
HST					(4.4)
Total					**19.49**
Less customer deposits					(7.0)
CWC requirement- 2006					**$12.5**
Note: 2005 CWC was calculated at $12.0; Average is **$12.25**					

*$479.0 million is the fuel budget in original filing

[316] The Board notes the comments of Mr. Drazen that there may be other potential sources of CWC such as a reserve for bad debts and the amortization of deferred financing charges (defeasance costs). The Board reiterates that this rate case provided the first occasion to conduct a meaningful review of the Company's CWC requirement. The Board is not prepared to make any further adjustment based on other potential sources of CWC at this time, but will continue to monitor this issue in subsequent rate hearings.

5.6 Total Rate Base

[317] NSPI has requested that its Average Regulated Rate Base for 2006 be set at $2.840 billion. Of that amount, $29.4 million is the CWC allowance. The Board has reduced the CWC allowance to $12.25 million which has the effect of reducing the rate base.

[318] The only other adjustment to rate base which appears to be justified on the evidence is to account for the increase in the long-term receivable resulting from the settlement between NSPI and its natural gas supplier. The settlement was reached after the application was filed and provides significant benefits to customers in the form of reduced fuel costs. The Board therefore approves an increase in the average rate base of $14.45 million to reflect the difference between the long-term receivable estimated in the original rate filing and the amount shown in U-76, which takes the settlement into account. To the extent that the Board's decision to increase the estimated natural gas resale benefit for the test year has the effect of further increasing the long-term receivable, then the Board will allow recovery of a return to reflect that increase. NSPI should include the amount of such increase , if any, in its Compliance Filing.

[319] NSPI also requested that the Board include an amount in rate base for the 2005 Q1 tax deferral. However, the amount of the tax deferral has not been finally determined as yet and, in the Board's view, it would be premature to include any amount

in rate base at this time. Carrying charges on the deferred taxes can be dealt with after the amount is determined and the Company applies to the Board for their recovery.

6.0 OPERATING, MAINTENANCE AND GENERAL EXPENSES (OM&G)

6.1 Overview

[320] NSPI projects a $27.8 million increase in Operating, Maintenance and General (OM&G) costs for the 2006 test year compared to the 2005 Compliance Filing. The proposed increases for each of the four operating groups are set out in the following Table compiled by the Board, based on information set out in NSPI's application[109]:

OM&G COSTS - Proposed increases (Dollars in Millions)			
	2005C	**2005F**	**2006**
Power Production	$66.0 M	$70.4 M	$75.3 M
Customer Operations	65.3 M	67.6 M	77.0 M
Corporate Support	37.1 M	36.8 M	44.4 M
Corporate Adjustments	13.6 M	5.6 M	13.1 M
Total OM&G	**$182.0 M**	**$180.4 M**	**$209.8 M**

[321] In its application, NSPI states that the proposed increases reflect greater costs associated with its enhanced storm response and storm proofing of its transmission and distribution system, extra spending on power production, maintenance and operations, wage increases, higher pension expense, higher regulatory costs and increased investment in demand side management. These issues are discussed below.

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[109] Exhibit N-1, pp. 70-105 and Exhibit N-2, Appendix B, p. 1

6.2 Power Production

6.2.1 Submissions - NSPI

[322] Power Production includes expenditures associated with the operation and maintenance of NSPI's generation facilities, as well as general costs for fuel procurement and management. For the test year 2006, NSPI proposes to increase these costs by $9.25 million over the 2005 Compliance Filing. The primary components of this proposed increase include $4.0 million for increased labour costs associated with the new union agreement and non-union labour increases, $1.8 million to implement new succession planning and apprentice programs, $3.2 million associated with maintenance and scheduled outages, $1.0 million associated with fuel procurement and management, and net savings of $0.8 million achieved from other related accounts.

[323] With respect to the maintenance of the Company's machinery and equipment associated with its generation fleet, NSPI states that it requires an additional $3.2 million comprised of maintenance and plant outage costs required to maintain and improve the reliability and availability of the generation assets. It notes that increased investment in maintenance is essential as the age and expected output of the generation facilities increase. NSPI further notes that OM&G costs will increase in the short to medium term until some point in the future when further capital must be invested in generation facilities, followed by a corresponding decrease in OM&G spending.[110]

[110] Exhibit N-1, p. 80 and 84

[324] In support of its projected $1.8 million increase for succession planning and apprenticeship programs, NSPI cites a demographic study indicating that the Company risks losing almost 50% of its trade workforce to retirement in the next five years. Accordingly, it proposes to implement succession planning to actively assess the Company's ability to sustain and replenish its critical organizational roles over time. It also proposes to develop apprenticeship programs to allow the transfer of skills and knowledge to NSPI's employee base, resulting, it asserts, in a stable workforce in future years.[111]

[325] During his testimony, Rick Janega, NSPI's General Manager, Power Production, stated that the costs of approximately 6 to 8 apprentice positions are currently reflected in rates. These apprentices are involved in multi-year training programs so they enter NSPI's workforce over a number of years. He testified that the proposed spending increase represents an increment of an additional nine auxiliary power engineers at a total annual cost of $750,000.[112] The remaining $1.05 million cost of the succession planning program relates to training and professional development of about 25 supervisors and managers at thermal generating stations and seven engineering staff in Generation Services.[113]

[326] As noted above in this decision, NSPI continues its efforts to improve its fuel procurement and management activities within the Company. The $1.0 million increase associated with this effort includes increased labour expenses associated with developing

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[111]Exhibit N-1, p. 83

[112]Transcript, November 28, 2005, pp. 2282-2283; see also PWC IR-12

[113]PWC IR-12

the fuel team and hiring a senior coal expert, contracting services used to supplement fuel procurement and management, as well as consulting services relating to procurement strategy and fuel forecasting.[114]

6.2.2 Submissions - Intervenors

[327] In their submissions, none of the intervenors specifically addressed the proposed $9.25 million increase in Power Production costs. Further, the proposed increases under this category were not seriously challenged during cross-examination of NSPI witnesses.

6.2.3 Findings

[328] The Board has considered the evidence concerning the proposed increase for Power Production costs in the amount of $9.25 million. As noted above, this evidence was not seriously challenged during cross-examination of NSPI's witnesses, nor was it the specific topic of comment during submissions following the hearing.

[329] The largest component of the proposed increase in Power Production costs is directly attributable to increased labour costs resulting from a new contract between NSPI and its union representing 1,146 unionized employees, which was signed on December 2, 2004 and effective from April 1, 2003 until July 31, 2007. There is also a wage increase of 4.0% for all non-union labour. Similar union and non-union labour

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[114] Exhibit N-1, p. 85

increases have been proposed across all OM&G operating groups, including Power Production, Customer Operations and Corporate Support. While projected labour increases respecting prior years were reflected in Corporate Adjustments, there has been a corresponding downward adjustment in the Corporate Adjustments account for the 2006 test year to account for the assignment of labour increases to the other OM&G categories.[115] The Board approves the labour increases proposed for Power Production in the amount of $4.0 million.

[330] Further, in the face of a demographic study which suggests that NSPI risks losing 50% of its trade workforce to retirement in the next five years, the Board determines that it is prudent, but not to the degree proposed by the Company, for NSPI to expand its succession planning and apprenticeship programs to ensure that valuable skills and knowledge can be transferred to a stable employee base and that the Company is able to sustain important organizational capacity into the future. The Board notes that the proposed increase to be included in the test year represents a marked increase in spending for this activity. In the view of the Board, an additional amount of $1.0 million per year (rather than $1.8 million) should adequately address such issues for the 2006 test year. NSPI's Compliance Filing shall reflect this reduction of $800,000.

[331] The Board also approves the proposed $3.2 million increase destined for maintenance and scheduled plant outage costs. While customers of NSPI benefit from these expenditures as NSPI maintains and improves the reliability and availability of its

[115] NSPI Application, Exhibit N-1, p.103

generation fleet, the customers also benefit from another result of these expenditures - NSPI is able to forego, in the short to medium term, significant capital investment in new generation facilities.

[332] Finally, the Board approves NSPI's proposed costs of $1.0 million associated with the implementation of its fuel procurement and management practices to comply with previous directions of the Board on this topic. In prior rate decisions, the Board has directed that NSPI make fundamental changes in its fuel procurement function. As discussed, NSPI's activities continue in furtherance of these directions. The $1.0 million cost increase approved by the Board will help ensure that NSPI achieves the lowest possible fuel costs, to the ultimate benefit of its customers.

6.3 Customer Operations

6.3.1 Submissions - NSPI

[333] Customer Operations includes expenditures associated with Regional Operations (transmission and distribution systems), Transmission and Distribution Assets (fleet, vegetation management), the Ragged Lake control centre, and Customer Service Administration (call centre and billing). For the test year 2006, NSPI proposes to increase these costs by $11.7 million over the 2005 Compliance Filing. The primary components of this proposed increase include $4.0 million with respect to enhanced storm response procedures, $5.2 million for increased vegetation management, $3.5 million for increased

labour costs, $1.3 million for improvements in customer service and to the call centre, and net savings of $2.3 million achieved from other related accounts.

[334] NSPI's proposed cost increase for enhanced storm response represents an increase from $1.4 million presently included in rates to $5.4 million allocated for storm response in the 2006 test year. The Company notes that its approach to storm response has significantly changed since events like Hurricane Juan and the November 2004 snow storm. As a result, NSPI has implemented the Emergency Services Restoration Plan ("ESRP"), which incorporates many of the recommendations suggested by the Board's consultant, John Sherrod. In its application, NSPI described its increased activities related to storm response:

> The key elements of the ESRP include a centralized and integrated decision-making team, more and earlier advance preparation, and a more timely deployment of resources in response to a major outage event. When NSPI determines that approaching, severe weather is likely to result in significant customer outages, it responds with the plan's methodical, advance preparation phase. This includes movement of NSPI and in-province contract resources. NSPI power line crews and field operation support staff are put on stand-by in staging areas around the province, based on where the Company believes they will be best positioned for rapid deployment during and immediately following the storm. Call Centre and head office support staff are placed in hotels connected to the NSPI Call Centre in downtown Halifax.
>
> Advance mobilization also includes contract power line and tree crews from within the province being placed in accommodations near areas that could be affected by outages. This advance deployment results in increased labor, meal, accommodation and fuel costs, which are incurred even if the storm does not result in customer outages.
>
> The ESRP provides the basis for the Company's response to anticipated significant outage events. Based on experience implementing the plan, NSPI has more effectively responded to significant outages. The experience gained through 2004 and 2005 indicate that the additional resources required to better track and prepare for severe storms, staff the call

> centre in advance of severe weather, and restore power more quickly to customers results in an incremental cost of $4 million annually.
>
> (Exhibit N-1, p. 89)

[335] In support of its request that a total of $5.4 million be included for storm response in the revenue requirement, NSPI indicates that it has averaged $5.3 million in storm response costs since 2002.[116] Further, NSPI indicates that it spent $5.8 million in 2004 in responding to storms[117], and it expects 2005 storm response costs to exceed the Company's original forecast of $5.0 million "by a wide margin"[118].

[336] In its Reply to Closing Argument, NSPI emphasizes that it is not appropriate to compare its present request for $5.4 million for 2006 with the $5.8 million figure expended in 2004, the year which saw significant weather events like White Juan and the November 2004 snow storm. It notes that the ESRP was not in effect until the end of that year. Thus, it asserts, the cost of increased storm response activities is not fully reflected in 2004 spending levels. In response to Consumer Advocate IR-36, the Company states:

> The Emergency Services Restoration Plan (ESRP) represents a material change in the nature of NSPI's storm response. Since the adoption of the ESRP (during 2004), significantly increased resources are now engaged earlier by NSPI in order to prepare for impending storms. When bad weather is forecast, NSPI makes a decision to deploy. The weather may or may not materialize or may not cause the amount of damage predicted. NSPI will bear the costs regardless. This includes activation of out-of-province line worker crews, overnight lodging for call centre personnel, re-deployment of NSPI line worker crews within the province and advance logistics activation. In this mode of operation, whether or not these resources are ultimately required, costs are incurred.
>
> (Consumer Advocate IR-36)

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[116]Undertaking U-6

[117]NSPI Application, Exhibit N-1, p. 90

[118]NSPI Redacted Reply to Closing Argument, p. 13

[337] In their testimony, witnesses for NSPI explained that the ESRP sets out an appropriate response level depending on the projected severity of an impending storm. For planning purposes, storms are categorized according to anticipated severity with Level 1 storms being at the low end of the scale and Level 4 storms being the most serious. The ESRP assigns anticipated costs to the various storm levels, with the preparation for, and response to, Level 3 storms being the most costly. The preparation for a Level 3 storm is projected to cost $375,000, while an actual response to a Level 3 storm, if required in the end, is budgeted at $1,850,000. NSPI projects that storm response costs could range from a minimum of $3,725,000 to a maximum of $7,800,000, the difference being mainly attributable to the estimated occurrence of one Level 3 storm (on the low side) versus three Level 3 storms (on the high side).[119] For the 2006 test year, it projects $5.4 million for storm response. NSPI notes that, under the ESRP, no projected costs are assigned to Level 4 storms like White Juan and the November 2004 snow storm, which occur relatively rarely.

[338] In its application, NSPI also proposes to increase its spending on vegetation management from $5.2 million, currently reflected in rates, to $10.4 million for the 2006 test year. It asserts that the increased spending will focus on improving reliability on both the transmission and distribution systems, with $7.2 million forecasted to be spent on the distribution system, and the remaining $3.2 million allocated for spending on the

[119]Undertaking U-6

transmission system.[120] The proposed additional spending on the transmission system will, according to NSPI, allow for the treatment of an additional 700 hectares of the transmission corridor with a combination of mowing and herbicide applications, while the proposed investment on the distribution system will be directed towards increased reactive and proactive vegetation management. NSPI estimates that approximately 70% of the total spending on the distribution system will be allocated to rural feeders.[121] The Company states that its spending on vegetation management for the distribution system will be prioritized based on a Dollar per Avoided Customer Interruption basis.

[339] Improved customer service and communications are the basis on which NSPI seeks an additional investment of $1.3 million in 2006 rates. This figure is comprised of $500,000 in telephony technology improvements (including enhancements to and testing of the high volume call answer (“HVCA”) and interactive voice response (“IVR”) telephone systems), $300,000 for increasing quality assurance in the customer service area (e.g., process documentation, complaint investigations, and training programs to target specific areas identified through quality monitoring), and $500,000 for improved outage communication processes. This latter figure of $500,000 includes $150,000 on additional customer research to ensure outage processes are better matched to customer expectations and $350,000 on additional proactive communications to be conducted

[120] Undertaking U-9

[121] Undertaking U-9

annually to assist customers with storm preparedness for major weather events and to manage customer expectations regarding communication and restoration of power.[122]

6.3.2 Submissions - Intervenors and PWC

[340] A number of the intervenors opposed the proposed spending increase for vegetation management, noting that the proposal for 2006 effectively doubles the current budget for this activity. Many who opposed this increased expenditure submitted that NSPI had not shown the Board why this significant increase was justified. In its Closing Submission, the Consumer Advocate submitted:

> 50. One of the basic requirements to be met by NSPI in applying for an increase in rates is to show that each of the proposed expenditures is required and is the most economical or lowest expenditure that is needed. That requirement is particularly important when, as at present, significant rate increases are being sought at a time when both NSPI and its ratepayers are under financial pressure.
>
> 51. NSPI witnesses should expect that they will be required to justify proposed expense increases. That requirement is not satisfied merely by making the request for rate recovery of additional expenses. NSPI must demonstrate to the Board that it has conducted an internal evaluation and prioritization of its needs and that the requested expenses truly are necessary.
>
> (CA, Redacted Closing Submission, para. 50-51)

[341] In terms of the request for increased spending on vegetation management, the Consumer Advocate submitted that NSPI's justification for this increase is not demonstrated. The Consumer Advocate asserted that the Company provided very little information in its responses to Information Requests about the need for the requested level of increased spending on this activity and the benefits arising therefrom. In response to

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[122]NSPI Application, Exhibit N-1, p. 91

Consumer Advocate IR-37, NSPI responded to the request for information on its vegetation management spending as follows:

> NSPI's vegetation management expenditures are aimed at reducing vegetation conditions which are creating reliability problems (reactive) and those which have the potential to create reliability problems (proactive).
>
> These expenditures are not different from past practices, rather it is for performing greater amounts of vegetation management, consistent with past practices to improve reliability.
>
> Expenditures would be prioritized to provide the best return on the investment. This prioritization takes into account safety concerns, the number of customers involved and the nature and extent of the reliability impact.
>
> ...
>
> NSPI is projecting this level of increased spending over the foreseeable future. No final decisions or commitments have been taken or made with respect to the projected additional expenditures. This work is dependent on monies being approved." [Emphasis added]
>
> (Consumer Advocate IR-37)

[342] The increase in vegetation management spending is also opposed by Avon, noting that the proposed total spending of $10.4 million on this activity is further suspect in light of the fact that NSPI has recently consolidated its vegetation management activities with one third party contractor, achieving 20% savings on its costs. Thus, factoring in this savings, the projected budget for the 2006 test year would, in effect, be 20% over the proposed $10.4 million amount.[123]

[343] Avon also notes that during the Board's Power Outage Review earlier in 2005, NSPI indicated that tree trimming and widening of easements were the most cost effective means of improving the reliability of the system, estimating that these activities would cost an additional $5 million.[124] Despite this estimate, Avon highlighted that the

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[123]Transcript, November 14, 2005, pp. 195-196

[124]Transcript, November 14, 2005, pp. 189-191

additional $5.2 million now requested by NSPI only relates to tree trimming within existing easements rather than a widening of easements as proposed during the Power Outage Review.[125] Avon added that in NSPI's 69 KV Right-of-Way Widening Assessment filed with the Board in November 2005 pursuant to the Power Outage Review, NSPI described in detail its widening activities by corridor and kilometer, and estimated a budget of $500,000 for 2006 with respect to this work.[126] In contrast, Avon noted that no such plan was submitted during this rate hearing with respect to the proposed expenditures associated with vegetation management.

[344] Other intervenors also expressed concern about the extent of the increase sought by NSPI with respect to vegetation management. In its Closing Submission, the CME submits that the proposed increase "is too rich for what is required at the present time and it certainly is not timely with respect to the magnitude of the potential rate increased [sic] facing all Nova Scotians."[127] It urges the Board to ensure that any increased expenditures that it approves are indeed necessary and that the expenses are "matched" to the work that is actually required.

[345] HRM notes that the $10.4 million budget proposed for the 2006 test year is more than double the figure which was identified in the Capital Project Authorization filed by NSPI in 1999 and approved by the Board in 2001. It questions whether NSPI's request

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[125]Avon, Redacted Closing Submission, p. 43

[126]Undertaking U-7

[127]CME, Redacted Closing Submission, p. 13

for this increase in vegetation management is driven by the Company's reduction of Power Line Technicians.[128]

[346] The Province, however, is supportive of NSPI's request for additional spending of $5.2 million on vegetation management. It states that these costs are to be incurred in response to concerns raised during the Power Outage Review following the November 2004 storm, noting NSPI's response to Consumer Advocate IR-37, in which the Company expected the additional expenditures for vegetation management to result in a 25% improvement in tree related customer interruptions and a 30% improvement in related customer hours of operation. Nevertheless, the Province asked the Board to maintain a "watchful eye" to ensure that these expenditures translate into improved reliability.[129]

[347] Similarly, SEB submits that the Board should carefully examine NSPI's reasons for this increased spending before approving the Company's request.

[348] In its Report, PWC notes the Company's assertion that the proposed vegetation management expenses will help contain, but not reduce, spending in OM&G. While NSPI provided an estimate of improved reliability factors resulting from the additional investment in vegetation management, PWC claims that the Company did not provide an estimate of the savings to be achieved with respect to reduced outage and repair costs in future years. Given that lack of information, PWC is unable to conclude whether the additional $5.2 million is reasonable.[130]

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[128] HRM, Redacted Closing Submission, p. 17

[129] Province, Redacted Closing Submission, p. 25

[130] PWC, Pre-filed Evidence, Exhibit N-84, p. 21

[349] With respect to NSPI's request for an additional $1.3 million investment for improved customer service relating to telephony technology improvements, improved outage communication processes and increased quality assurance, the Province expressed concerns respecting the frequency of the expenses being sought by NSPI. In particular, it questioned whether a $250,000 stress test of the Company's telephony systems and monies for research on outage communications are necessary on an annual basis, given that NSPI's request, if approved, would effectively include these charges in rates. While acknowledging that this may not be an issue in 2006, the Province submitted that it should be considered in greater detail in future rate hearings.[131] PWC also concluded in its Report that certain of the expenses related to telephony technology appear to be one-time costs and recommended that they be included in the revenue requirement over several years.[132]

6.3.3 Findings

[350] For the 2006 test year, NSPI requests an additional $11.7 million in spending for Customer Operations.

[351] The Board approves the labour increases for Customer Operations in the amount of $3.5 million resulting from the new labour agreement discussed above.

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[131] Province, Redacted Closing Submission, pp. 25-26

[132] PWC, Pre-filed Evidence, Exhibit N-84, p. 23

[352] NSPI proposed an additional increase of $500,000 respecting succession planning for power line technicians. For the reasons described above respecting Power Production succession planning, the Board reduces the proposed spending increase from $500,000 to $300,000.

[353] With respect to the costs related to enhanced storm response, none of the intervenors seriously questioned the necessity for increased spending in this area. NSPI's request would increase projected expenditures in this category from the current level of $1.4 million per year to a total of $5.4 million in 2006 rates.

[354] The Board is mindful that NSPI has greatly enhanced its storm response activities since major storm events like Hurricane Juan and the November 2004 storm.

[355] As witnesses for NSPI described in their testimony at the hearing, the Company implemented its ESRP by late 2004, providing for advance preparation and more timely deployment of resources in response to a major power outage event. As noted in its evidence, not all forecasted weather events ultimately occur as projected. However, under the ESRP, advance preparation and mobilization are required in all instances.

[356] The Board is satisfied that NSPI's storm preparedness and response under the ESRP represents a marked improvement in service by the Company over that which is currently reflected in rates. Further, the Board is satisfied that the $5.4 million is representative of the current level of expenditures being incurred by NSPI on an annual basis for these activities. While present rates provide for annual spending of $1.4 million with respect to storm response, NSPI has averaged $5.3 million per year in storm response

costs since 2002[133]. Based on the implementation of its ESRP, with its consequent impact on the degree of preparation which hinges on the predicted severity of upcoming storms, the Board finds that the proposed annual cost of $5.4 million for NSPI's storm response is reasonable and appropriate. Moreover, based upon the Board's findings in its Power Outage Review, it is clear that NSPI's customers desire NSPI to provide these enhanced storm response activities. The Board commends NSPI for its efforts in implementing the ESRP and it approves the additional $4.0 million directed to this initiative.

[357] While the issue of vegetation management also arose in the context of the Power Outage Review, there was a difference of opinion among the parties at the hearing with respect to the necessity for increased spending for such activities. NSPI asserts that increasing expenditures on vegetation management to $10.4 million will improve reliability on both the transmission and distribution systems, but some of the intervenors note that this proposed increase will double the level of vegetation management currently reflected in rates.

[358] Having reviewed the evidence, it appears that the primary concern of the intervenors relates to NSPI's failure to fully justify the extent of the spending commitment being requested for this activity. For instance, in its Closing Submission, Avon notes that, following the Board's direction in the Power Outage Review, NSPI filed its 69 KV Right-of-Way Widening Assessment Report outlining in detail its proposed activities for 2006 by

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[133] Undertaking U-6

corridor and kilometer for widening the right-of-way along its transmission system .[134] In the report, NSPI provided a budget of $500,000 for its request, which the Board notes is intended to be a capital expenditure rather than an operating expense. While this particular $500,000 expenditure is not within the scope of this rate hearing, Avon identifies this report as the basis for its argument that NSPI failed to set out any similar detail with respect to its proposed increase for vegetation management from $5.2 million to $10.4 million.

[359] Likewise, the Consumer Advocate argues that NSPI's application is deficient in this regard. In its Closing Submission, the Consumer Advocate highlights the response provided by NSPI to CA IR-37, wherein the Company states that the increased spending is to be directed to conducting a greater level of vegetation management, consistent with past practices to improve reliability. In its IR response, NSPI adds that no final decisions or commitments have been taken with respect to the additional monies until they are approved by the Board.

[360] The Board observes that evidence to the same effect was given by witnesses for NSPI during the hearing. In cross-examination by Nancy G. Rubin, Counsel for Avon, Dan Muldoon, NSPI's General Manager of Customer Operations for Transmission and Distribution, confirmed that the Company had not compiled the details of the proposed spending:

> Q. Now, have the specifics of the plan been set out anywhere?

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[134] Undertaking U-7

A. (Muldoon) In general we have put together elements of the plan to focus on more proactive reliability-based trimming, as well as sustainability. The specifics on span by span, feeder by feeder, we're currently gathering that data through our inspection programmes now to put the plan together.

Q. And when do you anticipate that plan will be complete?
A. (Muldoon) We'll have that plan complete probably by the end of this year for implementation in 2006.

Q. So you're looking for approval of it now prior to the time that we have a chance to review the plan and the budgets and the work being done.
A. (Muldoon) The plan that we have would be -- would fully support the 10.4 million dollar span that we have in our 2006 ---

Q. My question had to do with the timing of it. You're looking for approval of spending, 10.4 million dollar spending, prior to the time that we get to see the details of that spending.
A. (Muldoon) That is correct.

(Transcript, November 14, 2005, pp. 196-197)

[361] Mr. Muldoon was further asked on cross-examination by Mary Ellen Donovan, Counsel for HRM, about NSPI’s proposed spending target in 2006 of 70% for the distribution system and 30% for the transmission system:

Q. When you built that number, did you develop a document that showed the basis upon which you developed that number that could be provided in an undertaking here?
A. (Muldoon) I believe we could. I think we have those dollars targeted towards the large programme elements. We wouldn't have specific feeder by feeder or segment by segment or span by span detailed data as of yet, but in general we would have a good idea where that money is to be directed to meet our customers' changing needs and expectation around storm-proofing the system.

(Transcript, November 14, 2005, pp. 209-210)

[362] In her testimony, Nancy Tower, NSPI’s Chief Financial Officer, reasserted Mr. Muldoon’s view that the Company is confident about where the additional expenditures for vegetation management can be directed. In response to questioning by Mr. Merrick, she stated:

...

A. (Tower) Mr. Merrick, if I could, I was previously – before being Chief Financial Officer was Vice-President, Customer Operations, and had responsibility for vegetation management as part of that. One of the things the customers have told us and having sat through the storm hearing, it was clear to me, certainly, that customers wanted increased reliability in the province. We would have a list of every feeder in the province, perhaps even by feeder segment, numbers of customers on it and the reliability that that feeder is currently experiencing. We would also -- we would prioritize each year depending on how much vegetation spending we had, and we would cut the list at a certain point depending on where the spending was knowing how much reliability that would give us. To get more reliability, we had to do more spending. We know exactly where we would go on the next feeder, and the next feeder segment, and where in the province with the five million dollars ($5,000,000). So it's very clear to us and we have a plan that would probably span a number of years out.

(Transcript, December 1, 2005, pp. 3227-3228)

[363] In assessing the request for additional spending on vegetation management, it is instructive to consider the Board's findings in the recent Power Outage Review. In that decision, the Board accepted various consultants' findings about vegetation management and its impact upon NSPI's transmission and distribution systems.

[364] In relation to the transmission system, Liberty concluded that NSPI's transmission maintenance practices were substantially in accord with good North American utility practices and that these practices did not contribute to the structure failures or outages occurring during the November 2004 storm:

> [36] With regard to the maintenance and design of NSPI's transmission structures, Liberty essentially found no areas of concern:
>
>> Liberty assessed NSPI's design of the failed transmission structures and sky wires and found them in accordance with the appropriate standards. The wind and ice conditions in the November storm created loadings on the structures and sky wires that exceeded design loadings by at least 200 percent. Liberty also found that NSPI's transmission inspection program complies with good utility practices and that transmission maintenance substantially complies with good utility practices. Neither transmission system inspections nor maintenance contributed to the effects of the

> November storm. Liberty concluded that although tree contact caused some storm transmission outages, NSPI's transmission vegetation management program is substantially consistent with good utility practices. NSPI needs to complete its program to widen and side-cut transmission system right-of-ways.
>
> (Exhibit N-19, p. 4)

> [37] Liberty found that NSPI's efforts in this regard conformed with North American utility practice. It also stated:
>
> > Liberty found no evidence that NSPI's staffing, maintenance, or inventory practices had any appreciable effect on the severity of the outages caused by the November storm.
> >
> > (Exhibit N-19, p. 15)
>
> (Board Power Outage Review, August 5, 2005, para. 36-37)

[365] During its inspection of the transmission system, Liberty made specific observations with respect to right-of-way clearance. In its report, Liberty stated that:

> Liberty observed that NSPI has numerous right-of-way issues to address, especially on its 69 kV lines. During its aerial assessment of the NSPI transmission system, Liberty observed that about 10 km of 69 kV line L-5532 from Digby to Big Falls routes along the road. Side clearances on this section appeared to be less than the 10 m required for its 69 kV lines located on right- of ways. A tree caused an outage on this line during the November storm, and was the fifth and last interrupted transmission path to Annapolis Valley. This caused the interruption of all remaining load and hydro generation in the valley. In addition, Liberty observed other locations, particularly in the western part of the province, where NSPI had not yet trimmed the 69 kV and 138 kV right-of-ways to full width.
>
> (Board Power Outage Review, August 5, 2005, para. 44)

[366] In its findings on the transmission infrastructure, the Board commended NSPI for its design, construction and maintenance practices. However, it noted Liberty's concerns with respect to the right-of-way clearance relating to certain transmission lines:

> [64] Finally, the Board notes Liberty's comments regarding the completion of ROW clearance relating to certain transmission lines, particularly in the western part of the Province. Liberty stated that:
>
> > In some locations, NSPI's 69 kV and 138 kV lines do not center in the right-of-ways. In 2004, NSPI started widening right-of-ways up to 10 feet on its 69 kV system, with permission, to provide the standard clearance from the lines to the right-of-way edges. It expended about $146,000 in 2004 for

> 69 kV right-of-way widening. It plans to spend about $350,000 in 2005 for right-of-way widening on radial 69 kV lines, those that most affect costumer [sic] service.
>
> (Exhibit N-19, p. 18)
>
> [65] Accordingly, the Board directs NSPI to file an assessment report, by November 30, 2005, describing the work that has been or will be performed to implement the completion of the transmission ROW clearance, and giving a timetable and estimated cost assessment.
>
> (Board Power Outage Review, August 5, 2005, para. 64 - 65)

[367] As a result of that direction by the Board, NSPI filed its 69 KV Right-of-Way Widening Assessment Report, which was filed in this hearing as Undertaking U-7.

[368] With respect to NSPI's distribution system, John Sherrod acted as the Board's consultant. While not specifically addressing vegetation management, John Sherrod's conclusions included:

> ...
>
> 3. The damages caused to NSPI distribution facilities by the subject storm are consistent with what would be expected with facilities in normal condition subjected to such weather factors.
>
> 4. The NSPI distribution inspection processes, both routine and post-event, appear adequate and appropriate to good asset management.
>
> 5. The damages resulting from the subject storm were not a result of any deficiency in NSPI inspection and maintenance processes.
>
> 6. The staffing levels of NSPI power line technicians (PLTs) as maintained for the past ten years and available at the time of the subject storm are within customary limits in the industry and did not have a negative impact on maintenance of NSPI distribution facilities or on storm outage response.
>
> 7. The NSPI Customer Average Interruption Duration Index (CAIDI) has increased over the past ten years coincident with the PLT staffing level reduction, and this issue should be addressed.
>
> (Board Power Outage Review, August 5, 2005, para. 78)

[369] The Board accepted Mr. Sherrod's assessment of the condition of NSPI's distribution system and again commended NSPI for its efforts in constructing, inspecting and maintaining the distribution system. However, at paragraph 216 of its Power Outage Review, the Board noted that NSPI's distribution system in the Digby County area and the western part of the province had not specifically been inspected. As a result of concerns expressed by customers from across the province during the hearing, the Board engaged Liberty to conduct field inspections of the areas referred to by members of the public and report their findings respecting the condition of NSPI's distribution system to the Board before November 30, 2005.[135]

[370] In the view of the Board, the results of the Power Outage Review provide a useful context for the assessment of NSPI's request for a doubling of its vegetation management budget. Liberty's report on NSPI's distribution system has since been filed with the Board in late 2005. The Board is now awaiting a response to the report from NSPI. In the circumstances, the Board considers it appropriate to defer any additional spending on vegetation management for NSPI's distribution system until a full evaluation is undertaken of Liberty's report. While the Board is mindful that NSPI is able to identify feeders upon which such monies could be expended, the Board determines that such activities would be premature given the pending deliberations following the filing of Liberty's recent report. The review of Liberty's report will also provide NSPI with the opportunity to outline the Company's estimates of the reduced outage and repair costs that can be

[135] Board Power Outage Review, August 5, 2005, para. 234

anticipated from increased vegetation management (a measure of the program's success recommended by PWC in its Report)[136]. Thus, in relation to vegetation management on NSPI's distribution system, the Board does not approve any increase in spending for the test year. The current level of expenditure for the distribution system shall remain at $3.6 million.

[371] With respect to additional spending to be directed to vegetation management on NSPI's transmission system, the Power Outage Review did identify specific areas of concern. In light of the significance of NSPI's transmission infrastructure, as well as the areas of concern outlined in the Power Outage Review, the Board approves the additional spending for vegetation management proposed by NSPI with respect to its transmission system. Based on NSPI's response to Undertaking U-9 filed during this hearing, the Board infers that the level of increased spending proposed for the transmission system is an additional $1.6 million. Accordingly, the Board approves this additional amount for vegetation management on NSPI's transmission system, over and above what is already reflected in current rates (i.e., for a total of $3.2 million).

[372] Accordingly, for the test year, the amount of spending for vegetation management approved by the Board shall be a total of $6.8 million ($3.2 million for the transmission system and $3.6 million for the distribution system). In approving this amount, the Board takes into account the fact that NSPI has recently negotiated a 20% saving with respect to all vegetation management activities as a result of outsourcing the

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[136]PWC Pre-filed Evidence, Exhibit N-84, p. 21

work to one third party contractor. This means that, in comparison to previous years, this approved budget should yield a 20% increase in services for the same cost.

[373] NSPI has also requested an additional $1.3 million to improve communication with its customers. In its Power Outage Review, the Board directed NSPI to undertake various measures to improve its communications with customers, including improvements to its telephony technology, the conduct of a stress test on its system, reviewing the "call overflow management system", and developing a communications plan to improve the Company's interaction with its customers respecting the reporting of power failures and the restoration of service.[137] The Board also determined that a major problem during significant power failures was the inability of NSPI's customers to advise the Company of power outages, to inquire about the problem, and to determine the estimated restoration time. The Board directed NSPI to report its progress on these various issues by September 30, 2005. The Company's request for an additional $1.3 million stems, in part, from these issues raised during the Power Outage Review.

[374] The need to improve NSPI's HVCA and IVR telephone systems was highlighted in the Power Outage Review. The failure of these two systems contributed to many of the communication problems which arose during the November 2004 snow storm. Based on its findings during that Review, the Board determined that NSPI's customers expect these systems to accommodate their needs during power outages. The Board

[137] Board Power Outage Review, August 5, 2005, para. 187 - 200

approves the amount of $500,000 with respect to enhancements to the HVCA and IVR telephone systems, as well as the testing of the systems.

[375] However, the Board is not satisfied that NSPI's request for the remaining $800,000 is warranted with respect to increased customer research respecting outage communication processes, additional proactive communications with respect to storm preparedness and increased quality assurance in the customer service area. Both the Province and PWC questioned the annual nature of these requested expenditures, PWC adding that some of the expenses appeared to be one-time costs. While the Board concurs that some increased expenditure in these areas is justified, it does not accept NSPI's view that an $800,000 increase is required on an annual basis, particularly in the context of the significant rate increase being requested by the Company. In these circumstances, the Board reduces the additional $800,000 amount for these remaining activities to $300,000 per year.

[376] In summary, the Board approves $500,000 with respect to telephony technology improvements and $300,000 with respect to improved outage communication processes and increased quality assurance in the customer service area.

6.4 Corporate Support Groups (excluding DSM)

6.4.1 Submissions - NSPI

[377] Corporate Support Groups include expenditures associated with providing services for regulatory compliance, accounting, internal controls, governance,

administration, investor relations, human resource management, stakeholder communications, procurement, and information technology.

[378] For the test year 2006, NSPI proposes a net increase in these costs by $7.3 million over the 2005 Compliance Filing. The primary component of this proposed increase stems from the Company's proposed increase of $5 million related to the Marketing and Sales Group and its Demand Side Management ("DSM") initiatives. The Board's discussion of the issues surrounding DSM are contained elsewhere in this decision. The remainder of the net increase related to the Corporate Support Groups is comprised of various other increases and decreases proposed to be allocated to various function groups falling under Corporate Support. During the hearing and in closing submissions, the intervenors focused their attention on a proposed net increase of $400,000 requested for Investor and External Relations and Environment ("Investor and External Relations"), as well as an additional $2.0 million sought with respect to Regulatory Affairs. In its report filed in advance of the hearing, PWC raised a third issue respecting a net increase of $470,000 being claimed by NSPI's Finance Group for compliance with securities regulators.

[379] With respect to Investor and External Relations, NSPI identified a $492,000 increase in advertising costs over 2005 Compliance expenditures, resulting in a net increase of $400,000 with respect to the Investor and External Relations Group. It indicated that this amount will be directed to "communication designed to better engage

and educate customers about issues important to the overall operation of the utility". It identifies these issues as follows:

> The issues covered in this communication would include, but would not be limited to: DSM (energy efficiency and conservation); changes in environmental regulations, environmental progress; renewable energy; global energy prices; and storm preparedness. The functional delivery of the DSM program remains entirely within Customer Service.
>
> (Avon IR-20)

[380] NSPI states that the $492,000 amount is allocated to various forms of communication, including $150,000 for ongoing development of the next generation of web-based interactive communications with customers and other stakeholders.

[381] NSPI also proposes an increase of $2.0 million in spending for Regulatory Affairs of the Corporate Support Group, increasing its $2.6 million spending level in the 2005 Compliance Filing to $4.6 million for the 2006 test year. The Company asserts that the $2.0 million increase is comprised of additional Board assessment fees, additional NSPI and Board consulting and legal fees associated with "increased regulatory activity" and the additional cost of a consumer advocate.[138] In their testimony, witnesses for NSPI indicated that the $1.6 million increase is associated with the Company's 2007 rate application, which it expects to file in 2006. A further amount of $400,000 is also claimed for an increase in the 2006 Board assessment.

[382] In addition to the above $2.0 million increase, NSPI seeks to recover as part of the 2006 test year costs a further $2.0 million with respect to the costs of the present 2006 rate application conducted in 2005, and an increase of the Board assessment charge

[138] NSPI Application, Exhibit N-1, pp. 96-97

to NSPI in 2005. This $2.0 million is included in the Corporate Adjustments account of the rate application. Noting that the 2006 rate application costs and the increased Board assessment for 2005 were not provided for in 2005 rates, NSPI, in effect, seeks to defer the expenses from 2005 and include them as costs of the 2006 test year. In NSPI's view, this treatment is consistent with previous deferrals of operating expenses and allows the matching of the revenue (i.e., 2006 revenue) with the associated costs (i.e., the 2006 rate hearing conducted in 2005 and the incremental portion of the Board assessment incurred in 2005).[139]

[383] NSPI also seeks a net increase of $470,000 to ensure regulatory compliance with the Ontario Securities Commission ("OSC") following the OSC's adoption of new governance and audit regulations contained in guidelines approved by the Canadian Securities Administrators in February 2005. Both NSPI and Emera must adhere to these regulations, which require the Chief Executive Officer and the Chief Financial Officer to provide certification with respect to disclosure controls and internal controls respecting financial reporting. Moreover, the certification requires a more rigorous attestation process by external auditors.[140]

[384] The additional compliance costs associated with the new OSC regulations total $941,000. This figure is comprised of $565,000 for consulting costs attributed to work needed to comply with the new governance regulations and $376,000 for external legal

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[139]Province IR- 53; PWC IR-21; Exhibit N-1, p. 104

[140]NSPI Application, Exhibit N-1, p. 95; PWC IR-25

and audit costs associated with the review of the regulations.[141] Half of the projected increase of $941,000 is to be allocated back to Emera through Corporate Support Transfers, leaving a net increase of $470,000 for NSPI.

6.4.2 Submissions - Intervenors and PWC

[385] Avon opposes both the $492,000 incremental increase with respect to advertising under Investor and External Relations, as well as the recovery, in the 2006 test year, of the costs for the hearing held in 2005 respecting a rate increase for 2006.

[386] With respect to the proposed $492,000 incremental increase for Investor and External Relations advertising, Avon submits:

> 218. It seems evident that there is some element of double-counting given that NSPI is also seeking $5 million associated with DSM which has, as its largest component, communications and promotions as well as an incremental increase of $4 million for storm response which likewise has, as a large component, communications, (although denied by NSPI).
>
> 219. While a half million dollars may not seem like much in the grand scheme of Nova Scotia Power's overall revenue requirements, it is indicative of the cavalier approach which NSPI has adopted in putting together its revenue requirement. Intervenors are unable to assess the reasonableness of the expenses and particularly, where line items such as advertising suggest duplication and a significant increase over prior spending, it is respectfully submitted that NSPI must do more to discharge its burden to show that these expenses are reasonable and properly chargeable.
>
> 220. If NSPI wishes to spend money on communications which have the effect of promoting NSPI and generating goodwill in the community, then it may do so. However, similar to the Board's decision with respect to sponsorships, as reaffirmed in the 2002 rate case, this should not be included in the revenue requirement to be recovered from ratepayers.
>
> (Avon Redacted Closing Submission, p. 46, para. 218 - 220)

[141] NSPI Application, Exhibit N-2, Appendix B, p. 7 of 52

[387] In its Closing Submission, Avon also opposes NSPI's proposed recovery of its costs for both the 2005 and 2006 rate applications in the same test year.

[388] Avon argues that it is "manifestly unfair" to ask ratepayers, in the same test year, to bear the burden of the costs associated with both the 2006 rate case (held in 2005) and 2007 rate case (contemplated for 2006). In response to NSPI's assertion that this can be treated as an "amortization of deferred operation costs", Avon states that a request for the deferral of costs for a rate hearing is unprecedented. Citing **Philadelphia Electric Co. v. Pennsylvania Public Utilities Commission**, 502 A(2d) 722 (1985), Avon submits that a utility is not entitled to seek recovery of a shortfall in a prior rate hearing's expense line item unless such expenses were extraordinary, unanticipated and of a non-recurring nature.[142] Avon observes that regulatory expenses are clearly a line item for which NSPI sought and received rate revenue in a prior test year (i.e., 2005) and that the costs for the 2006 rate application (held in 2005) were not unforeseen, extraordinary or non-recurring.

[389] The Province also opposes the recovery of $2.0 million in the 2006 test year with respect to regulatory expenses incurred in 2005 for 2006 rates. It questions NSPI's submission about matching expenses with revenues in the same test year. Further, the Province suggests that the costs of a rate application should be "levelized" over the number of years the rates resulting from that application are expected to remain in effect.

[142] Avon Redacted Closing Submission, pp. 44-45

Otherwise, it observes that the full costs of a rate application could remain in rates for future years in which no rate case is undertaken.[143]

[390] The proposed increase related to regulatory costs is also opposed by the CME. In addition to its view that the costs of two annual rate applications should not be recovered in the same test year, the CME echoes Avon's concern that the proposed increase in costs should be fully documented and justified.

[391] Finally, both Avon and the Province submit that, if the Board considers it appropriate to approve the expenses occurred in 2005 for recovery in 2006, the same treatment should be accorded to the rate application being contemplated by NSPI in 2006 with respect to 2007 rates.

[392] PWC reviewed NSPI's request for a net increase of $470,000 relating to its compliance with the new OSC regulations. While PWC suggested that some of the one-time documentation and setup costs could be deferred over the period of benefit, it did not object to inclusion of such costs in the test year given their relative magnitude. However, it noted that on July 29, 2005, following the filing of NSPI's application for this rate hearing, a one year delay in the implementation of the regulations was announced. In a response to PWC IR-43 respecting this delay in the implementation of the regulations, NSPI confirmed that it intends to complete the documentation and testing of its internal controls in 2006, as planned, but that it may defer the increase in audit fees that NSPI will incur to

[143] Province Redacted Closing Submission, para. 63-64

2007. PWC submitted that these cost deferrals should be estimated and excluded from the 2006 test year.[144]

6.4.3 Findings

[393] In addition to the issue of the proposed increase for DSM, the intervenors raised three issues with respect to the proposed spending increase for Corporate Support Groups: 1) the incremental increase of $492,000 related to Investor and External Relations' communication and advertising expenses, and 2) the $2.0 million proposed increase related to Regulatory Affairs. PWC raised a third issue, 3) the necessity of including all of NSPI's request of $470,000 for increased regulatory compliance respecting more stringent governance and audit requirements.

[394] In response to Avon IR-20, NSPI confirmed that the proposed increase of $492,000 for advertising is to be directed to forms of communication which would "better engage and educate customers about issues important to the overall operation of the utility". It noted that the issues to be covered include matters relating to DSM, changes in environmental regulations, renewable energy, global energy prices and storm preparedness.

[395] In the opinion of the Board, most of the issues sought to be canvassed by NSPI in its increased advertising relate to activities already contemplated in other sectors of the Company's operations and, as such, constitute an overlapping or double counting

[144] PWC Pre-filed Evidence, Exhibit N-84, p. 19

of expenses claimed elsewhere in rates. For instance, communications related to storm preparedness are, and should be, part of the proposed spending increase for storm response under Customer Operations and all communication expenses associated with DSM should be budgeted within the DSM envelope. Further, the Board concurs with Avon's submission[145] that other expenses related to promoting the Company's corporate image and enhancing its goodwill in the community should not be included in the revenue requirement being sought from customers.[146]

[396] Thus, the Board denies the Company's request for a $492,000 increase for advertising activities carried out by the Investor and External Relations group, and the Board directs that OM&G expenses be reduced accordingly.

[397] NSPI seeks a $2.0 million increase for the 2006 test year to cover the estimated regulatory costs associated with an increase in the 2006 Board assessment, and a rate application expected to be filed in 2006 with respect to 2007 rates. In addition, under the Corporate Adjustments category, NSPI also seeks a further $2.0 million for regulatory expenses incurred in 2005 associated with the present rate case and the increased 2005 Board assessment. The Board considers it appropriate to consider these requests together.

[398] NSPI asserts that the $2.0 million amount being claimed for each of the present and upcoming rate cases, as well as the increased Board assessment for 2005

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[145] Avon, Redacted Closing Submission, para. 220

[146] Board 2002 Rate Decision, para. 138-139

and 2006, are not currently reflected in rates. The 2005 Compliance Filing shows that $2.6 million is allocated for Regulatory Affairs spending. In its application, NSPI states that the $2.0 million increase is comprised of additional Board assessment fees, additional NSPI and Board consulting and legal fees associated with "increased regulatory activity" and the additional cost of a consumer advocate.[147]

[399] The Board has serious reservations about NSPI's request to defer the expenses incurred in 2005 with respect to the present rate case and the increased Board assessment for 2005. While the Board is mindful that expenses for the hearing were incurred by the Company with respect to 2006 rates, it has been NSPI's practice to write-off these expenses in the year in which they were incurred. In the Board's opinion, it is not reasonable to burden ratepayers with the cost of two rate hearings and two increased Board assessments in the same test year, which would be the case were the Board to permit NSPI to roll such costs forward into the 2006 test year.

[400] In the case of NSPI, it appears that the costs associated with rate applications will be of a recurring nature. While NSPI has not filed a rate application in each and every year, such applications are becoming rather common and, if an application is filed in 2006 with respect to 2007 rates (as witnesses for NSPI have indicated is likely), then it will mark the fourth such application since 2002. In fact, in presentations to outside parties, NSPI has anticipated annual rate filings, at least until 2008.[148] Further, given the

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[147]NSPI Application, Exhibit N-1, p. 97

[148]NSPI presentation to Standard & Poor's, Exhibit N-30, SEB IR-95, Attachment 5, p. 16

environment of rising fuel costs over the past few years, the possibility of rate applications, including one in 2005 for the 2006 test year, could, in the opinion of the Board, have reasonably been foreseen by NSPI and, therefore, should have been estimated in the 2005 test year figures. Lastly, NSPI's regulatory costs were included as an expense line item, for which the Company sought and received revenue from rates. Such expenses typically come in above or below projections. The Board does not require NSPI to refund any surplus related to a particular expense category[149], nor does it consider it appropriate for NSPI to seek a deferral of any shortfall in relation to an expense item which could have been reasonably anticipated.

[401] For the above reasons, the Board denies NSPI's request to defer the costs of the 2005 rate hearing to the 2006 test year. Accordingly, this proposed deferral under the Corporate Adjustments category is not approved and the Compliance Filing for 2006 shall be adjusted to reflect this finding.

[402] However, the Board does approve NSPI's request for additional spending of $1.6 million associated with the anticipated rate application to be filed in 2006 for 2007 rates. In doing so, the Board is mindful that the approved increase of $1.6 million for Regulatory Affairs is a significant increase and, as noted by the Province, the full costs of a rate application will be included in rates in future years even when no rate case is undertaken.

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[149] For example, NSPI's interest expense is expected to be about $5 million less than projected in 2005, see Transcript, November 22, 2005, p. 1024

[403] Upon review, it appears that the Board's annual assessment currently reflected in rates is $593,000 (the 2000 assessment)[150] and that, for the year ending March 31, 2005, the annual assessment increased to $997,457. This increase is not currently reflected in rates. The Board approves the increase of $400,000 for inclusion in 2006 rates with respect to the March 31, 2006 year end. However, for the reasons explained immediately above, the Board denies NSPI's request to recover the increased assessment relating to March 31, 2005. In support of this conclusion, the Board observes that NSPI would have had an estimate of the annual assessment for March 31, 2005, prior to the filing of its 2005 rate case, which was filed on May 28, 2004[151], and revised on June 23, 2004[152]. It should be noted that the annual assessment has increased gradually since 2000. Consequently, it was certainly possible for NSPI to have made a reasonable estimate of the 2005 assessment when it applied to increase rates for that year.

[404] New governance and audit regulations adopted by the OSC will result in higher regulatory compliance costs. In its application, NSPI projected these costs to be a net amount of $470,000 for the 2006 test year. After NSPI's application was filed, a one year delay in the implementation of these governance and audit regulations was announced. In response to PWC IR-43, NSPI stated that it intended to complete the documentation and testing of its internal controls in 2006, as originally planned. However, it indicated that it may defer the increase in audit fees to be incurred by the Company to

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[150] NSPI Application, Exhibit N-1, p. 97

[151] Board 2005 Rate Decision, March 31, 2005, para. 7

[152] Board 2005 Rate Decision, March 31, 2005, para. 4

2007. PWC recommended that NSPI estimate the amount of this cost deferral and that such costs be excluded from the 2006 test year.[153] The Board concurs with the opinion of PWC. It directs that half of the proposed net increase be deferred to 2007, resulting in a net increase approved for this activity of $235,000 ($470,000 less 50% recovered from Emera).

[405] In conclusion, the Board approves the increased OM&G spending proposed by NSPI for Corporate Support Groups in the amount of $7.3 million over the 2005 Compliance Filing, subject to reductions of $492,000 respecting advertising and communication expenses by the Investor and External Relations group; $4.45 million with respect to DSM as set out elsewhere in this decision; and a net amount of $235,000 respecting implementation of new governance and audit regulations by the OSC.

[406] While the Board approves the $1.6 million expenditure increase under Regulatory Affairs respecting a 2007 rate case expected to be filed in 2006, the expenses for the rate hearing held in 2005 are denied under Corporate Adjustments. Further, for the same reasons, the increase of $400,000 relating to the increased Board assessment for 2005 is denied. However, the estimated increase of $400,000 for 2006 is approved.

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[153] PWC, Pre-filed Evidence, Exhibit N-84, p. 19

6.5 Corporate Adjustments

6.5.1 Submissions - NSPI

[407] This category comprises expenses which are not specifically assigned to a business unit or functional area, including year-end payroll accrual, incentives, deferred severance, capital overhead contributions and pension expenses. While there is a proposed decrease of $500,000 for Corporate Adjustments from $13.6 million (2005 Compliance Filing) to $13.1 million for the 2006 test year, a significant component of this expense category relates to pension expense which is proposed to increase from $26.0 million (2005 Compliance Filing) to $31.7 million for the 2006 test year. This represents an increase of $5.7 million in pension expense. The basis for this increase is explained by the Company in its application:

> Pension expense is projected to be $31.7 million in 2006 compared to $26.0 million in 2005C, an increase of $5.7 million. The primary reason for the increase in pension expense is the adoption of updated mortality tables used by actuaries to determine pension funding and a lower discount rate used to value outstanding obligations. The updated mortality assumptions show that on average, people are living longer, which results in pensions being paid for longer periods of time. This shows up as an increase in pension expense. Additionally, the discount rate estimated is presently 5.5% versus 5.75% in 2005C. NSPI's actuary, Paul Chang of Morneau Sobeco has provided the Company with the appropriate discount rate for CICA 3461 reporting purposes. Based on single "A" bonds, the current discount rate as of May 31, 2005 that would be used to determine CICA 3461 expense for NSPI is 5.5%.
>
> (Exhibit N-1, p. 105)

[408] In PWC IR-23, NSPI provided a reconciliation of the pension expense from the 2005 Compliance Filing to the 2006 test year, accounting for the factors described above:

Pension Expense - Reconciliation of Benefit Cost	
2004 Actual Benefit Cost	**$21.9 M**
Exclude impact of Amendment No. 12 Change in discount rate (6% to 5.75%) based on “AA” corporate bonds Other factors	$ 0.9 M $ 2.7 M $ 0.5 M
2005 Compliance Benefit Cost (prior to Amendment No. 12)	**$26.0 M**
Include impact of Amendment No. 12 Change in definition of high quality debt instrument used to determine discount rate from AA corporate to A corporate	$(1.9) M $(2.7) M
2005 Forecast Benefit Cost	**$21.4 M**
Change in discount rate (6% to 5.5%) based on “A” corporate bonds Change in mortality table Other factors	$ 5.4 M $ 4.5 M $ 0.4 M
2006 Forecast Benefit Cost (per Rate Case)	**$31.7 M**

6.5.2 Submissions - PWC and Intervenors

[409] PWC was retained by Board Counsel to review, among other issues, the pension expense. In its report filed as Exhibit N-84, PWC concluded that the policies followed by NSPI in forecasting pension expense for the 2006 test year are reasonable:

> Changes in two major actuarial assumptions account for most of the $10.3 million increase in pension expense in 2006.
>
> Effective in 2006, NSPI’s assumptions with respect to mortality of pension plan beneficiaries is based upon an updated mortality table giving recognition to the fact that people are living longer and will draw pension benefits for a longer time. This is a fairly common, recent change made by other companies with defined benefit pension plans and was approved for adoption by the Canadian Institute of Actuaries in 2005. We consider the change reasonable and appropriate.
>
> The total impact of this change upon the pension benefit obligation is estimated to be $26.4 million. This higher liability will be expensed over 10 years and in 2006, $4.5 million will be recognized in pension expense.
>
> At December 31, 2005 a discount rate will be assumed for purposes of valuing the pension and post-retirement benefit liability at December 31, 2005. For regulatory and test year

purposes, NSPI has assumed a rate of 5.5% will apply for 2006, based upon rates at May 31, 2005. This 0.50% reduction in the discount rate from 2005, causes an overall increase in the liability of $51.6 million and an increase in pension expense in 2006 of $5.4 million.

Management also makes assumptions concerning expected remaining life of employees, retirement age, salary increases, mortality, etc. NSPI's actuary has provided an opinion respecting the reasonableness of these assumptions for the 2006 test year.

For general purpose financial statements and rate regulation purposes, pension expense is being measured in accordance with generally accepted accounting principles...
. . .

Discount Rate

The discount rate used to determine the present value of liabilities in the pension plan and the current service cost for each period has decreased from 5.75% in the 2005 rate case to 5.50.% in the 2006 test year. This 2006 assumption was based on the interest rate on high quality bonds at May 31, 2005. The discount rate applicable to NSPI's 2006 pension expense will be determined based upon market interest rates on high quality bonds as at December 31, 2005. Since May, 2005, bond yields have decreased by 25 to 50 basis points and forecasts indicate further declines in the months ahead.

Thus, the discount rate used of 5.50% for the Test Year is, in our opinion, likely at the high end of the current range of 5.00% to 5.50%. The lower the discount rate the higher the liability, and the higher the expense. Lowering the discount rate also results in an initial actuarial loss on the accrued benefit obligation, which must be included for amortization into expense.

...

CONCLUSION

Major assumptions with respect to expected rate of return on assets and forecasted discount rate for liability valuation are at the high end of reasonable ranges. Reductions in either of these rates would result in higher pension expense and ultimately a higher rate request. In our opinion the policies followed by NSPI in forecasting pension expense for the Test Year are reasonable.

(PWC, Pre-filed Evidence, Exhibit N-84, pp. 10-13)

[410] The Board did not receive any comment from the intervenors on the pension expense issue.

6.5.3 Findings

[411] In support of its proposed increase for pension expense, NSPI filed an actuarial report outlining the basis for this increase. PWC, the Board's consultants, have reviewed the actuary's analysis and conclusions. Following its review, PWC filed a report stating that the pension expense is being measured in accordance with generally accepted accounting principles, that the assumptions being made by NSPI with respect to pension expense are reasonable and that the policies followed by NSPI in forecasting pension expense for the 2006 test year are reasonable and appropriate.[154]

[412] No significant concerns were raised by any of the intervenors at the hearing.

[413] In the circumstances, the Board accepts the evidence of NSPI and PWC that the forecasted pension expense for the 2006 test year is reasonable. The Board approves the increase in the amount of the pension expense from $26.0 million in the 2005 Compliance Filing to $31.7 million for the 2006 test year, an increase of $5.7 million.

[414] With respect to the remainder of the Corporate Adjustments sought by NSPI, the Board approves all of the said adjustments, except the proposed deferral of $2.0 million associated with regulatory expenses incurred by the Company in 2005, as discussed in the preceding section. Accordingly, the Board directs NSPI to reduce the Corporate Adjustments budget from the proposed amount of $13.1 million to $11.1 million for the 2006 test year.

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[154]PWC, Pre-filed Evidence, Exhibit N-84, pp. 9-13

6.6 Summary of OM&G Findings

[415] The following table contains the disallowances made by the Board with respect to OM&G:

OM&G DISALLOWANCES (Dollars in Millions)		
Power Production		
Succession planning Subtotal	$ 0.8	**$0.8**
Customer Operations		
Vegetation management Communication processes Succession planning Subtotal	$3.6 0.5 0.2	**$4.3**
Corporate Support		
DSM Advertising costs OSC compliance Subtotal	$4.45 0.49 0.24	**$5.2**
Corporate Adjustments		
2005 Regulatory costs Subtotal	$2.0	**$2.0**
TOTAL		**$12.3**

[416] A summary of the overall impact of the Board's findings respecting OM&G is shown in the following table compiled by the Board:

TOTAL OM&G COSTS - Approved increases (Dollars in Millions)					
	2005C	**2005F**	**2006 Proposed**	**Board Disallowance**	**2006 Board Approved**
Power Production	$66.0 M	$70.4 M	$75.3 M	$0.8 M	$74.5 M
Customer Operations	65.3 M	67.6 M	77.0 M	4.3 M	72.7 M
Corporate Support	37.1 M	36.8 M	44.4 M	5.2 M	39.2 M
Corporate Adjustments	13.6 M	5.6 M	13.1 M	2.0 M	11.1 M
Total OM&G	**$182.0 M**	**$180.4 M**	**$209.8 M**	**$12.3 M**	**$197.5 M**

[417] Thus, the Board approves an increase in OM&G expenses from $182.0 million (2005C) to $197.5 million for the 2006 test year.

6.7 OM&G - Operations Review

6.7.1 Submissions - NSPI

[418] For the 2006 test year, OM&G expenses are proposed to increase from $182.0 million in the 2005 Compliance Filing to $209.8 million for 2006, an increase of $27.8 million (15.3%). As indicated above, the Board reduced the 2006 test year expenses to $197.5 million, thereby reducing the increase to 8.5%.

[419] NSPI maintains that it is effectively monitoring its OM&G costs. It states that OM&G expenditures have been stable over past years as base costs have been

maintained on a relatively flat basis through a variety of cost containment measures. In NSPI's submission, the increases proposed for 2006 are driven by new investments.[155]

[420] NSPI also notes that the Company's success in managing its OM&G costs is supported by earlier reports filed with the Board in 2003 and 2004. It points out that these reports provided details with respect to various aspects of its OM&G management, including financial processes and procedures for controlling expenditures, cost containment strategies, an overview of OM&G expenditures by type, an analysis of OM&G expenditures by operating units, and comparisons to external benchmarks. It maintains, as stated in its report filed on September 2, 2004:

> NSPI's OM&G performance benchmarks extremely well when compared to its Canadian peers, as demonstrated in this report.[156]

[421] NSPI outlined various cost containment strategies undertaken by the Company to control OM&G expenses, including improved matching of resources to the work required, ensuring that the most competitive resources are used to complete tasks, investing for the lowest long term cost, setting targets and conducting tracking to achieve continuous improvements.[157]

[422] During the hearing, the Policy Panel described NSPI's approach to managing its OM&G costs in response to questions posed by Mr. Grant:

> Q. Do your customers wish to see NSPI increase its efficiencies and productivity?

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[155]NSPI Redacted Closing Argument, p. 65

[156]NSPI Application, Exhibit N-1, p. 72

[157]NSPI Application, Exhibit N-1, pp. 73-77

A. (Tedesco) I think they have a right to expect that,and I think the record is clear that, in fact, over the last several years that's precisely what we have done.

Q. In your budgeting process, do you indicate to your managers targets which you would like to see them hit in terms of reducing costs?

A. (Tower) Having worked for Mr. -- both Mr. Huskilson and Mr. Tedesco as Vice-President of Customer Operations and being responsible for virtually half of the costs at Nova Scotia Power, I'd like to give you a bit of flavour of budgeting and the kind of culture that exists at Nova Scotia Power, and I think this follows on -- Mr. Chairman, follows on a bit from your question to Mr. Blunden yesterday. So -- and just by way of example, back in the fall of 2003 would have been a typical budget round, as we would call it. We were under significant pressure to reduce costs. And at that time, I would have been working directly for Mr. Huskilson. And I, like the other Nova Scotia Power executive, would have been pushed pretty hard to come up with cost savings as much as we possibly could. Mr. Tedesco was arriving in January and we wanted to make sure that we had a budget that we felt was as stretchy, is a word that we would use, as it could possibly be. And so we put something together that we thought was challenging for us and would be challenging for our teams. In January, 2004, Mr. Tedesco arrived and his -- the first thing that he did was ask us to cut those OM&G costs even further. And while we had -- you know, we had believed that we had cut as far as we possibly could, we had to look for even more savings as a result of Mr. Tedesco's direction. And we did -- we did look for those and we did get them. Things in my organization such as putting a single power technician in a truck, for example, and putting a shift on and using the truck for two shifts is something that we've done. Looking at automatic meter reading to determine whether it makes sense. Looking at sole sourcing our vegetation contract. *I would tell you that pursuit of OM&G savings is not an event at Nova Scotia Power. It is just something that we do all the time*. And, in addition, certainly our last general increase for staff overall would have been in January, '03. So we're asking our staff -- we're asking our managers and our staff to do this at a time when we've held their salaries fairly constant. So I just wanted to give that flavour because it is something that we are -- and with the cost pressures that we face as a result of our fuel increase, it is something that we've lived with and we've continued to look for each and every day that we work there. And I would say we do balance that, though, with customer service to make sure that we don't go any further than we need to and ensure that we provide the customer service that we need. One of the things that we've done is to understand very clearly our unit costs and understand our customer service levels and understand when we take costs out what that does to service. And so it is -- *it does become a balance, but at the end of the day I would tell you and if you'd ask many of the people that worked for me, cost saving is something that we do.* And I have continued that with me as I -- in my role as Chief Financial Officer, to ensure we're in a -- you know, we're budgeting again this year. This is the time of year that we do it. And certainly that philosophy would ring loud and clear.

A. (Tedesco) I would just add to that that Mr. Merrick asked me, and I don't know if you were in the room at the time, Mr. Grant, whether or not there were additional things that we could do this year. And I think my answer was something to the effect that

> this year in particular we have all the incentive we need to do whatever we can to control costs. *And it was my judgment that controlling costs further from where they currently exist would cause deterioration in the service, and I still hold that judgment*. [Emphasis added]
>
> (Transcript, December 1, 2005, pp. 3065-3069, emphasis in original)

[423] NSPI submits that a special cost reduction initiative or exercise was not specifically undertaken in anticipation of this rate application because of its existing cost containment and control measures, which it describes as significant.[158]

6.7.2 Submissions - Intervenors and PWC

[424] A number of intervenors expressed concern about the proposed increase in OM&G costs. In its Closing Submission, Avon asked the Board to "engage management consultants to review NSPI's control of its OM&G expenses with a view to identifying best utility practices and further potential savings."[159] Avon suggested that this would be an opportune time to conduct such a review, given the size of recent rate requests and the fact that the Company anticipates further rate applications in 2006 and 2007.

[425] The Consumer Advocate also expressed disappointment about NSPI's alleged failure at the hearing to show that it had taken reasonable and necessary steps to control costs and to demonstrate that the increased expenditures are justified:

> ... NSPI argues that it has discharged the burden of showing that it has taken reasonable and necessary steps to control costs and to ensure that the increased expenses being sought for recovery in rates are justified.

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[158]NSPI, Redacted Closing Argument, p. 69

[159]Avon, Redacted Closing Submission, para. 166

> What is missing in the testimony of the NSPI witnesses and in the final submission is any description of a procedure set up by the Company to screen, evaluate and prioritize whether the increased expenses are necessary and justified. For example, it would be reasonable for a company, seeking to increase its prices, to establish some process internally to evaluate the need for increased prices. All that the Board is left with in this application is evidence of the expenses for which recovery is sought. There is no basis to assess why those expenses were chosen, what other possible expenses were excluded and who and how the need for the expenses was evaluated.
>
> NSPI should be put on notice that in future applications in which it is seeking recovery of additional expenses, it will be expected to show an internal assessment process to verify the need for the amount of the expenses.
>
> (CA, Redacted Rebuttal Submission, para. 24-26)

[426] While other intervenors did not specifically request a review or report with respect to the control of OM&G expenses, a few of the intervenors expressed concern about the necessity and justification for some of the increases, to the extent that they asked the Board to closely monitor the spending of the Company with respect to its activities.[160]

[427] In a report filed on behalf of Board counsel, PWC expressed concern about NSPI's OM&G costs going forward into future years. It noted that the OM&G cost per customer, in constant dollars, is projected to increase by over 12.5% from $383.4 million in the 2005 Compliance Filing to $431.6 for the 2006 test year.[161]

[428] Noting that NSPI failed to provide requested information respecting OM&G costs for 1996 - 2003 and forecasts for 2007 - 2008, PWC stated:

> Given such limitation, we are unable to comment on the reasonableness of the 2006 level of OM&G cost per customer or in total, as comparisons with the historical or forecasted future

[160] Province Redacted Closing Submission, para. 58 (Enhanced Storm Response), para. 59 (Vegetation Management) and para. 60 (Telephony/Communications); CME Redacted Closing Submission, para. 24 (Vegetation Management & Storm Response) and para. 25 (Regulatory Costs)

[161] PWC, Pre-filed Evidence, Exhibit N-84, p. 14

trends are an important indicator in that regard. In particular, we have not been able to establish whether certain of the 2006 forecast OM&G costs are one year 'spikes' in costs or whether they are expected to continue at 2006 levels going forward.

As noted above, NSPI has asserted that 2007 and 2008 OM&G costs are expected to continue at or above 2006 levels. Should the growth in customer base remain low, this statement suggests possible future increases in OM&G per customer in the near term.

The lack of availability of forecasts for 2007 and 2008, the fact that NSPI does not have detailed OM&G forecasts, the very high level forecast provided in response to PwC IR 22 along with the underlying stated assumptions, as well as the significant increase in the forecast filed, all raise concern about the level of OM&G costs going forward.

Conclusions

We believe that it would be prudent for NSPI to provide, in support of future rate cases, detailed five year forecasts of OM&G costs. The review of such forecasts, we believe, would increase overall transparency, and allow the Board to see the quantification of certain forward-looking plans and programs such as capital vs. maintenance plans for each of the production facilities, DSM costs, regulatory costs, vegetation management and other storm response costs. It will also identify expected problem area where cost control measures may be implemented in a proactive manner.

We also recommend, due to the sharp increase in OM&G costs and OM&G costs per customer, that NSPI undertake a detailed benchmarking study to compare its costs, by category, to the costs being incurred by other similar utilities.

(PWC, Pre-filed Evidence, Exhibit N-84, pp.15-16)

6.7.3 Findings

[429] In past decisions, the Board has expressed concern about the control of OM&G expenses by NSPI. In its 2002 rate decision, the Board stated:

[133] The Board has significant concerns with respect to whether NSPI has reduced corporate expenses to the fullest extent feasible and whether there are adequate controls on spending.

[134] The Board's authority in this area is found in Sections 42(2) and 45(1) and (2) of the Act which are set out earlier in this decision. The difficulty faced by the Board is that there is simply insufficient information available to determine whether the expenses outlined in Appendix 1 of Exhibit N-1 are appropriate to be charged to ratepayers and are as low as prudently possible. NSPI is requesting ratepayers to bear these and other costs through a significant increase in electricity rates. It is, therefore, incumbent on the utility to satisfy the Board, through the public hearing process, that ratepayers' money is wisely and frugally spent. No such assurance is evident from the information which has been filed.

[135] Further, the Board is concerned that NSPI's internal budgeting procedures are not sufficiently thorough to ensure expenses are as low as possible.
...

[136] The Board believes that it is incumbent on NSPI management to be able to demonstrate that it has made every effort to operate on a cost efficient basis when it seeks to increase electric rates in Nova Scotia. Intervenors have raised valid questions concerning certain expenses. NSPI has not provided an adequate response. As a result, the Board is not satisfied that NSPI management has made every reasonable effort to eliminate unnecessary expenses.

[137] Further, the Board understands that a "benchmarking" process is utilized by NSPI in setting overall spending levels. While this is a useful procedure, it should not be used to the exclusion of other methods of determining the appropriate level of expenses, including a careful and exhaustive review of NSPI's operating expenses in an endeavour to ensure that it is operating as efficiently as possible.
...

[140] The Board's concern in this regard goes beyond the present filing which projects NSPI's 2002 test year expenses. It appears from this rate proceeding that while overall OM&G costs have not increased appreciably in the six years since the last rate hearing, certain corporate expenses have increased significantly. The Board notes that there are no studies, evidence of internal management reviews, or details of cutbacks on OM&G expenses on file with the Board. The Board believes there is a pressing need to demonstrate that cost reductions at NSPI affect the higher levels of the company as well as lower levels.

[141] In view of the Board's concerns in this regard, the Board has determined that NSPI shall undertake a detailed review of the current level of OM&G expenses and submit a report to the Board which demonstrates that NSPI is operating as cost-efficiently as possible. After examining the report, the Board will determine if a further study is required. If further action is required, the Board may appoint an independent consultant to perform the study.

(Board Decision, October 23, 2002, para. 133-141)

[430] During his testimony during this hearing, Mr. Huskilson reiterated the approach taken by NSPI in the review of its costs:

Q. (Merrick) ... earlier about steps that you were taking to cut costs and expenses. Do you agree with that as a component --that that is part of what should be -- that that is a component that should be in every application for a rate increase, that is, that the company has -- puts forward the steps that it has taken to minimize its own expenses and also to minimize the requirement for increased rates? Do you agree that that should be, from here on in, a component of an application?

A. (Huskilson) Well, I would say is I think the -- especially the operating maintenance and general costs, but generally all of the costs of the company need to, I think, have two things happen. No. 1, I think they have to have a regular and solid review, which is something that we clearly did, in my view, in the last rate hearing. As well, the company has worked to report appropriately on those costs and continue to report on those costs. I don't know if that's something that we have to do every time we come before a rate -- a revenue requirement review, and the reason I say that is because there are ways to look at whether the company is doing a good job in that area, things like bench marking and looking at where the company sits against other companies who do the same kind of work. So I think there are mechanisms in which that can be reviewed. But I would say that it is very important that the costs are reviewed in great detail on an ongoing basis and that there is a special review at appropriate time frames.

(Transcript, December 1, 2005, pp. 3219-3220)

[431] The Board questioned the Finance Panel about the Company's review of OM&G costs in the context of NSPI's request for a large rate increase:

Q. (Chair) NSPI is coming to the Board seeking a rate increase, an average rate increase of 13 percent. This is after a rate increase last year. So would you agree that in this situation NSPI has a special responsibility to review all areas of operating costs to see whether or not any cost efficiencies can be achieved?
A. (Blunden) Yes, I would agree with that.

Q. Was that review done in this case?
A. (Blunden) Yes. I mean, NSPI has always focused on reducing its costs to levels -- to the most appropriate level possible. I believe we continue to do that. I think our OM&G report filed a couple of years ago and updated for the last rate application would demonstrate that. There had been a number of individual expense items that seemed to be occurring at this point in time, whether it's the regulatory climate, whether it's through customer expectations on storm response, or changing pension expense, but from our perspective the costs are reasonable and reflective of what's needed to run the business in 2006.

Q. But the result is that after you've done this review your requested rate increase still averages 13 percent. So my question was how did you go about reviewing the -- and let me just back up a bit. When I mentioned operating expenses, the only operating expense we're talking about is what's in OM&G, is that correct? There's no other operating expenses per se. I'm not talking about capital expenditures, I'm talking about operating expenses.
A. (Blunden) Yes, I understood you to mean OM&G expenses, correct.

Q. Yes. So in view of that, then, how did you go about reviewing the OM&G expenses to see whether or not there could be additional savings achieved in order to reduce a requested rate increase? OM&G has increased by, I think, somewheres around 29 million dollars, which is about a 15 percent increase in this year. So I understand that some are higher by necessity, but the question is how did you go about reviewing the different categories of operating expenses to see whether or not you could make cuts or other savings?

A. (Blunden) Certainly as part of our annual business planning process and as part of this rate application we always look at our operating expenses and determine, you know, certainly a starting point from baseline perspective whether we think they're reasonable, and that certainly has not changed. When we look at, in particular, how difficult this year has been from a financial perspective, our baseline OM&G costs are where they're at. The increases that are before the Board at this hearing are -- and are very specific, they're specifically related to pension expense. An example would be as we change the methodology coming up with the discount rate last year, which has had the effect of reducing pension expense by 2.7 million dollars as an example, or they're tied to initiatives like demand side management or storm response. So from a baseline perspective despite load growth -- and our operating expenses may be characterized slightly different than they would be in some companies. Our operating expenses include the variable labour at our plants and our linesmen and those kinds of things. You know, load is up, customers are up, inflation is up and the fact that we've been able to keep our baseline OM&G flat over quite a number of years I think speaks volumes to how well we manage our baseline costs.

Q. But I think what I was trying to get at is whether or not you had -- you went through an internal exercise to look at these expenses and say -- recognizing that from a benchmarking perspective they may be in line with other utilities, but that really wasn't my question. My question was did you have an internal exercise to go through these expense items line by line, item by item, to see whether or not you could, by reorganizing or restructuring some of your internal departments, whether or not you could achieve additional savings in view of the significant rate increase that you're requesting the Board to approve?

A. (Blunden) And I think the only thing I can probably respond to that is it's not -- we didn't undertake a different exercise but it's kind of part of how we do business on a daily basis. Certainly, at least quarterly, if not monthly, we would meet or a couple of us would meet with some of the senior managers in all the operating units and review their year-to-date spending and where there's possibilities for cuts. Anything that we believe is possible to do we have reflected in our 2006 rate application in terms of cost reductions.

Q. I'm not sure that that completely answered my question. Was there an exercise or an activity, a specific activity, internal, to look at these expenditures to see where cuts could be made from -- obviously you can't cut if service is going to be impaired, that's a given, but in any entity there are always some areas where it's a worthwhile exercise to look at these things and take a hard line on the expenditures to see whether or not -- what would happen if you did eliminate some or reduce some or make certain restructuring in your operation. Was that type of an exercise carried out?

A. (Blunden) It has been over a number of years, and what I mean by that is that approach has been taken to all of our OM&G costs over the last number of years, which is why we've been able to maintain them to where they're at. To the extent of where future opportunities, we have not identified -- any opportunities that we have identified have been reflected in this application and we have not been able to identify any additional opportunities that wouldn't have a significant impact on service.

Q. Was anything done in connection with this rate application that was different than what you've been doing every year for the last few years? And, to be fair, I recognize that OM&G has been discussed extensively in the past, but this is somewhat of a different situation. And so was anything done differently this time than what you do every year?

A. (Blunden) No. Again we believe the approach we have taken is an appropriate one and we maintain that approach.

(Transcript, November 30, 2005, pp. 2725 - 2730)

[432] With respect to PWC's suggestion that NSPI should provide multi-year forecasts of projected OM&G spending levels, Mr. Blunden questioned the merit of such an exercise:

A. (Blunden) We do not do detailed OM&G forecasts multi-years out, that's correct.

Q. (Deveau) In terms of PriceWaterhouseCoopers, however, they believe that you should, shouldn't you, because they say at page -- if you refer to page 16, starting at line 4:

> "We believe that it would be prudent for NSPI to provide in support of future rate cases detailed five-year forecasts of OM&G costs. The review of such forecasts, we believe, would increase overall transparency and allow the Board to see the quantification of certain forward-looking plans and programs including..."

And just -- obviously DSM is in there and regulatory costs are in there as well, isn't that right?

A. (Blunden) Yes.

Q. And just further on that point -- and this is arising, I think, from questions that Mr. Merrick and Mr. Mahody asked you in terms of cost-efficiency programs – wouldn't such projections into the future for OM&G costs -- wouldn't they provide a valuable tool for assessing cost-efficiency in the management of NSPI in terms of OM&G costs? And I suppose my final question is, do you agree with PriceWaterhouse's recommendation that such projections should go five years in advance? Sorry, five years into the future.

A. (Blunden) If I could direct you to our rebuttal evidence, on page 84, we -- our intention was to respond to the suggestions made by PriceWaterhouseCoopers. In isolation we believe three-year forecasts or multi-year forecasts of OM&G by themselves is not overly relevant because -- and there's a whole list of things that influence that, whether it's load growth, changes in the regulatory environment, pension expense, those kinds of things. For any of our planning purposes, unless we know of the specific change in an area of our OM&G, we have found over time that increasing it by inflation for management purposes is a reasonable proxy only because a number of the other line items have a much greater likelihood of changing more materially, for example, fuel expense.

Q. But that's not the case in this year, is it, because this year the increase [for OM&G] is quite significant?

A. (Blunden) Yes, and some of the increases that we're experiencing -- and whether it be increased pension expense because of changing discount rates or incremental costs that have been, you know, I guess, the results of storm hearings and those kinds of things -- would not have been things that we would have been able to forecast three years ago. So, those would be examples of multi-year forecasts in OM&G that in isolation wouldn't necessarily be overly relevant.

Q. So, is what you're saying that you don't believe that three or five-year forecasts are helpful at all in assessing expenses into the future?

A. (Blunden) I think in areas where you believe there are going to be step changes in some of your operating costs I think they can be useful, but they are just forecasts. We tend to believe that a more appropriate evaluation of our operating cost structure is looking at where we're at today versus where other utilities are, what our trend has been, so focusing more on actual results and informal comparisons as opposed to future forecasting.

(Transcript, November 30, 2005, pp. 2708-2711)

[433] Following its review of the evidence in this hearing, the Board continues to be concerned about the magnitude of the increase sought by NSPI for OM&G expenses, particularly since it accompanies NSPI's request for a very significant rate increase. In its application, NSPI is seeking an increase of $27.8 million in OM&G costs for the 2006 test year. This represents a 15.3% increase over the 2005 Compliance Filing. Moreover, OM&G spending is not insignificant, representing 24.5% of the total projected cost of operations.[162]

[434] While the Board accepts NSPI's evidence that the Company's management endeavours to contain line expense amounts, it is not persuaded that NSPI has taken sufficient steps to critically examine its entire operation to determine the most efficient use

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[162] NSPI Application, Exhibit N-2, Appendix A, Table 2 ($209.8 M of $858.0 M)

of its resources. In the opinion of the Board, any large entity should regularly undertake such a review, without reference to, or reliance upon, traditional or existing operational groups. Such a review should focus on developing the most efficient organizational structure as the Utility moves into the future.

[435] Accordingly, the Board directs that an operations review be carried out on NSPI's operations. The review shall encompass a detailed examination of NSPI's organizational structure, its level of OM&G expenditures, and any other pertinent areas which may come to light, with a view to determining whether cost savings and operational efficiencies can be achieved. NSPI is directed to prepare the terms of reference for the operations review and submit them to the Board for approval by May 31, 2006. The terms of reference shall also set out the procedures for identifying and selecting the firm or person who will perform the operations review.

[436] PWC has recommended that future rate applications contain detailed five year forecasts of OM&G costs. The Board accepts this recommendation and directs NSPI to include detailed five year forecasts of OM&G costs in all future rate applications.

7.0 DEMAND SIDE MANAGEMENT

7.1.1 Overview

[437] In the 2005 rate decision, the Board directed the Company to initiate a technical conference process with respect to a Demand Side Management ("DSM") plan.

> [267] The Board has considered the helpful information provided on the matter of DSM during this proceeding. In the Board's view, further work and progress with respect to DSM is both important and necessary. The Board understands the suggestion that a DSM hearing should be held and, indeed, such a hearing may well be ordered in future. At present, however, the Board believes it is more appropriate to direct NSPI to initiate a technical conference process, with interested parties and stakeholders, to pursue an improved and effective DSM program for the Utility.
>
> (Board Decision, March 31, 2005, para. 267)

[438] NSPI stated in this application that it is currently engaged in a number of DSM initiatives which will reduce long term capacity requirements and environmental emissions. NSPI's current annual expenditures for DSM are approximately $0.5 million and it is proposing to increase this amount by $5.0 million annually as outlined in its rebuttal filing.

7.1.2 Submissions - NSPI

[439] NSPI's application outlined the process it followed to prepare its DSM Plan:

> ... , the Company invited a cross section of community leaders with an interest in demand side management to participate on a committee that will design and organize a special forum on energy conservation and efficiency planned for September 2005 in response to the Board's direction.
>
> The Company will incorporate feedback about past technical conferences and its November 2004 Customer Energy Forum to ensure that this technical conference process sets in motion an enhanced program of demand side management that meets the expectations of customers and other stakeholders.
>
> The specific new DSM programs to be implemented by NSPI will ultimately be a function of the ideas generated in the stakeholder consultations, in conjunction with technical feasibility

> and economics. NSPI will pursue opportunities to improve the economics of DSM programs through partnerships with other stakeholders.
>
> NSPI's increased DSM activities will provide tangible benefits to the environment, as well as practical means for customers of all classes to save money in the face of rising energy costs, particularly important to those in lower income situations.
>
> As a result of a number of existing DSM initiatives and awareness programs underway during 2004 and 2005, NSPI estimates a 0.5% reduction in forecast energy requirement for 2006. It is NSPI's view that an additional $5.0 million investment is the minimum required to ensure that the ongoing opportunities for DSM, as part of meeting the future energy needs of Nova Scotia, are fully optimized, and that the expectations of our customers to help them save money and reduce emissions are met.
>
> (Exhibit N-1, pp. 100-101)

[440] NSPI, in its Rebuttal Evidence, provided additional information and also included a copy of its proposed DSM plan "Conservation and Energy Efficiency Plan 2006" (the "Plan").

[441] NSPI is proposing to spend an additional $5 million in the test year on various initiatives included in the Plan. It has stated that if the Plan is approved by the Board the following objectives and results can be expected:

> Approval of this plan will advance energy efficiency and conservation in Nova Scotia. It will:
>
> - reduce electricity usage and save our customers money
> - reduce greenhouse gas emissions and help the environment
> - help build a conservation and energy efficiency culture in Nova Scotia, led by our young people and our schools
> - bring Nova Scotia Power together with community based partners in the province, leveraging the efforts and investments of all in its worthwhile pursuit
> - meet customer expectations that Nova Scotia Power do more to advance energy efficiency and conservation
>
> Specific Results to be achieved for 2007 include:
>
> - 72GWh reduction in annual electricity usage
> - Approximately $7.7 million in annual savings to customers from this reduction in usage

- 16 MW reduction in peak electricity demand
- 50 thousand tonne reduction of green house gases

(Exhibit N-153, Appendix A, p. 2)

[442] NSPI developed the Plan by identifying possible options, engaging a team of industry leaders to identify opportunities with the greatest potential, hosting customer forums, ultimately finalizing each element of the Plan. The Plan includes programs for residential, commercial and industrial customers. The Plan has three kinds of programs: programs led by NSPI; programs led by others; and future program development. Each of these programs has one or more of the following four elements: lighting; price awareness; workshops; and youth education. In addition to a cost benefit analysis, the Plan also provides a cost breakdown for each element of all programs.

[443] A detailed table of the proposed Plan is contained in Appendix D.

[444] The Plan includes the expected load reduction for each element of the Plan, and also provides a sensitivity analysis for variations in the expected load reductions for each element of the program.

7.1.3 Submissions - Intervenors and Dr. John Stutz

[445] Board Counsel's expert, Dr. John Stutz, along with a number of intervenors, were very critical of the Plan. NSPI compiled these criticisms as follows:

> 1. NSPI has not provided enough detail to allow UARB approval (Brockway, PWC, Stutz, Rosenberg, Drazen).
> 2. NSPI's approach to developing its Conservation and Energy Efficiency Plan is not consistent with good practice, and cannot result in a good plan (Brockway).
> 3. The consideration of NSPI's DSM plan should be conducted in a separate hearing process (Brockway, PWC, Stutz).
> 4. NSPI should implement inverted rates to promote energy conservation (Hughes).
> 5. NSPI should direct the entire $5 million investment to give away as many Compact Fluorescent Lamps (CFLs) as possible to NSPI's customers (Hughes).
> 6. The Board should disallow the 0.5% forecasted effect of DSM on 2006 load (Drazen).
> 7. NSPI has not provided a forecast of DSM spending beyond 2006, so it could decide not to spend any additional money in 2007, after obtaining the funding as part of rates (Rosenberg).
> 8. NSPI's proposal harms those customers who do not participate in the programs (Rosenberg, Drazen).
> 9. NSPI should allocate no share of the DSM investment to SEB.
> 10. NSPI could make money by "selling" DSM to customers in return for their first year savings, which are assumed to be twice the DSM investment made by NSPI. This profit margin of 100% would be used to lower rates.
>
> (Exhibit N-153, pp. 87-88)

[446] Avon believes that the Plan is premature and questions the process followed by the Company:

> 176. At its most basic level, we respectfully submit that the request for $5 million for DSM spending is premature in the absence of a well thought out plan which sets priorities based on long term planning and short term goals and does a cost-benefit analysis of the options. NSPI itself in a presentation made to the Energy Research and Development Forum in Antigonish in May of 2004 had stated that the initial step in the establishment of a plan should be consideration of load objectives and development of programs to meet these objectives as measured against an objective analysis. Instead, NSPI's initial step was the establishment of a $5 million budget.
>
> (Avon, Redacted Closing Submission, p. 37)

[447] Avon also questioned whether the Plan benefits the customers:

> 178. For the $5 million expense, NSPI estimates a reduction of forecast load in the range of 72 GWh. The cost for the DSM however is higher than the avoided fuel cost savings. For expenditures of $5 million in 2006, ratepayers can look forward to reduced revenues greater than the avoided generation cost of $1.83 million which will further be required to be made up in rates.
>
> (Avon, Redacted Closing Submission, p. 38)

[448] Avon expressed reservations about the success of the Plan, especially with respect to its emphasis on residential customers:

> 183. 75% of the $5 million in the DSM plan is in the residential sector and about 85% of savings are to come from the residential sector. This is stated to be largely due to the use of compact fluorescent lighting (CFL's) and a grade 5 education program. In cross-examination, Mr. Outhouse challenged the panel with an extract from the Environmental Commissioner of Ontario Annual Report indicating that the commercial and institutional sectors could offer substantial savings. NSPI was unable to point to any hard analysis that showed there were not similar opportunities in these sectors in Nova Scotia.
>
> (Avon, Redacted Closing Submission, p. 39)

[449] The Consumer Advocate submits that the proposed expenditures are not based on a need assessment analysis. He questions the appropriateness of the Plan's elements, their costs and effectiveness:

> 34. The method of developing the program gives little confidence that it is an appropriate expenditure of ratepayers money. The $5 million was not based on any analysis of what was needed to implement specific programs. Rather NSPI chose the amount and then looked for ways to spend it. The amount was arrived at by May, 2005 prior to any effort being made to develop the program itself. It was primarily motivated by an estimate of what NSPI understood to be the typical range of amounts expended by other utilities on DSM programs in relation to their total expenditures. The $5 million was allocated to the various rate classes prior to the development of the program. Having identified the amount to be spent, it was only in July that the company began the process of seeking input for the purposes of identifying elements of the program. After the elements of the program were identified it was either intentional or fortuitous that the original allocation of costs to the rate classifications were as originally allocated.
>
> (CA, Redacted Closing Submission, p. 9)

[450] The Consumer Advocate also expressed concern about the possibility of a conflict of interest on the part of the Company in its implementation of the Plan. He stated that:

> 46. One of the issues to be addressed by the DSM program is whether it should be administered by NSPI or by an independent entity. There are a [sic] areas of concern when a utility itself administers a DSM program.
>
> - There is a conflict of interest. The basic function and purpose of a utility is to sell as much energy as possible. The objective of a DSM program is to reduce the sale of energy. The conflict is illustrated by the fact that the majority of the DSM funding which NSPI has proposed would be administered by the sales and marketing department (see Application page 97).
> - Projecting large energy reductions as a result of a DSM program results in higher rates that then turn into bottom line profits if the reductions are less than projected.
> - There may be a temptation to use DSM funding for essentially a PR program.
> - There may be a temptation to use DSM funding to cover existing administrative and staffing costs.
>
> 47. For those reasons, one of the issues to be addressed is whether it would be practical for an independent entity to administer a DSM program in this jurisdiction.
>
> 48. For similar reasoning, we recommend that the choice of the consultant be either at the discretion of, or approved by, the Board. Input as to the selection of the consultant should be available not only to NSPI but to any interested stakeholders.
>
> (CA, Redacted Closing Submission, pp. 12-13)

[451] The CME is of the view that the Plan is incomplete, and only a limited amount of funds should be approved to complete the Plan:

> 23. It is the view of the CME that only a limited amount of money be allocated for the test year for the design of a DSM program. It is also the view of the CME that there are likely many benefits that accrue to NSPI in the short and longer term and that it could be funded wholly by NSPI and if not, should be amortized over an appropriate period of time.
>
> (CME, Redacted Closing Submission, p. 12)

[452] Ms. Brockway questioned the expertise of the Company to prepare the Plan:

> Q. So, can a utility design an effective DSM program without drawing on individuals with specific utility DSM expertise?
>
> A. In my opinion, a utility cannot design effective DSM programs without drawing on individuals with professional DSM design expertise. Utility DSM efforts are specialized programs. DSM program designers need considerable experience and expertise, whether they are on the staff of the utility, or their expertise is acquired from outside the utility. I am not saying that a utility should draw its program designs only from the conventionally-accepted set of approaches to DSM that are in widespread use among utilities. After all, I am chair of a non-profit devoted to disseminating information on an innovative approach that is not yet in widespread use. However, I am saying that a utility (and its regulator) cannot hope to understand the problem it is trying to solve with DSM programs, and cannot understand the pros and cons of available DSM options, without drawing on expertise regarding the myriad DSM efforts that have been funded by utilities in the last 20 years. [Indeed, a detailed awareness of the reasons for program failure is as useful as awareness of what programs are standard practice.]
>
> (Exhibit N-87, pp. 20-21)
>
> ...
>
> Q. Are you saying the public is not qualified to draft a DSM program?
>
> A. I am saying that drafting a utility DSM Program is as technical an exercise, and requires as much expertise and professional experience, as drafting a plan for installation of a substation, or preparing a load forecast, or designing rates. The expertise is different, but it is needed nonetheless. The devil is in the details, many things that appear intuitively obviously turn out not to work as one might think, and it is all too easy to reinvent a poorly-functioning DSM “wheel” rather than achieve a program design that could work according to its specifications. Reasonable DSM

experts can and do disagree on how best to achieve with DSM goals, but at the very least they can call out these issues to the attention of the Board for its ultimate determination.

(Exhibit N-87, p. 23)

[453] Ms. Brockway outlined some key components which she recommends be explored before the Plan can be evaluated:

Q. Please describe some necessary elements of a DSM plan that the Company has not yet developed.

A. Before a DSM program can be evaluated, certain key components need to be developed. Without limitation, these include (a) determination of the cost-effectiveness standard for measures and programs [which in turn is guided by a clear understanding of the legitimate purposes of a utility DSM effort], (b) the target markets for DSM offerings [e.g. should programs be designed to provide benefits to all customers, even if it is less cost-effective to serve DSM needs of some customers?], (c) budgets for each class and for each program, informed by the overall goals of the initiative and by the cost-effectiveness results for various measures and programs; (d) allocation of costs to classes and subclasses based on principled allocation factors; and (e) cost-effectiveness screening of all measures and programs against the cost-effectiveness test or test that is chosen for the initiative, the program or the measure, as the case may be. It is also important to specify how the program will be evaluated, so that necessary data gathering can commence with program roll-out.

(Exhibit N-87, pp. 18-19)

[454] The Ecology Action Centre argues that the Company placed too much focus on lighting in the Plan, leaving other important areas under-funded and under- recognized:

The EAC supports NSPI in their dedication of five million dollars towards DSM in the upcoming year, and the commitment that NSPI senior staff has displayed to working with other organizations to build a DSM plan which they believe will maximize their investment.

The Ecology Action Centre continues to have reservations about the current heavy focus on lighting in NSPI's DSM plan. NSPI's assertion that breakthroughs in lighting technology and their associated costs have occurred that would allow for energy savings with a small investment is valid. The heavy focus on lighting, however, leaves other important areas under-funded and under-recognized, and risks ignoring more substantial energy efficiency improvements.

> The EAC maintains that Nova Scotians would benefit more, in the long term, from additional DSM initiatives involving retrofits and increased awareness and efficiency in the areas of space and water heating.
>
> At present, NSPI's Conservation and Energy Efficiency Plan is the major method by which changes to Nova Scotian power use may be targeted. These changes are required to support our commitments to Kyoto and to the New England Governors/Eastern Canadian Premiers Climate Change Action Plan. As these commitments have been made on behalf of Nova Scotians, they deserve assurance that the commitments will be met. This program deserves the continued input of Nova Scotians and oversight on their behalf.
>
> The EAC continues to call for a demand side management hearing early in the year 2006 as an ideal opportunity for government and NSPI to work collaboratively on DSM and pollution reduction initiatives.
>
> (EAC, Redacted Closing Submission, pp. 5-6)

[455] The Electrical Consumers Alliance of Nova Scotia was in full support of the Plan at the start of the hearing process. However, based on the evidence provided during the hearing, ECANS tempered that support:

> However, upon reflecting, we agree that a deferral is probably in the best interests of all parties - ratepayers and shareholder.
>
> We are convinced NSPI has the full complement of talent to successfully implement a DSM program. On that, there is no doubt. What is at question is the level and degree to which the contents of this particular DSM concept have been debated in the public forum. It also has not been measured against 'tried and proven' DSM programs in other jurisdictions.
>
> So, taking a small step sideways, we now believe the best value for DSM dollars can be obtained by:
>
> > Locking the $5 million into rates for 2007.
> > Including $500,000 in rates for the year 2006 to allow NSPI to move forward as explained below.
> > Engaging an external DSM consultant to advise all parties on DSM components that are tailored for NSPI ratepayers.
> > Hold technical conferences (both before and after) the consultant prepares his/her report.
> > Including DSM as a formal portion of the hearing to set rates for 2007.

In this way, there can be more certainty that we will save as much as we spend. It is imperative we get DSM right.

(ECANS, Redacted Closing Submission, pp. 13-14)

[456] Halifax Regional Municipality supports DSM, but does not agree with the Plan as proposed by NSPI:

b) Comments on the Energy Conservation Plan

The plan addresses only a start to energy efficiency and conservation. Unfortunately, the plan does not address any load shifting initiatives. A DSM plan needs to address both aspects of DSM, energy conservation and load shifting as recognized by Chuck Faulkner in Exhibit N-162. A DSM plan also needs to have a long term vision to be able to set short term goals. As has been pointed out, a DSM plan should have measurable results and a feedback and reporting mechanism to both consumers and the UARB. HRM believes that there is a shared responsibility between NSPI and its customers to implement an effective DSM Plan; however it is the UARB's responsibility to create the guidelines and incentives to enable DSM to happen effectively. As noted by the Consumer Advocate, NSPI noted that there were aspects of the program that had not yet been developed.

Due to the importance of DSM, the setting of DSM targets, budgets, timelines and the means of measuring DSM success need to be included in any DSM plan. Additional economic incentives that create the climate for a sustainable DSM Plan incorporating measurable energy efficiency and load shifting goals should also be considered for inclusion. As an example, a higher ROE on effective DSM expenditures might be considered.

(HRM, Redacted Closing Submission, p. 12)

[457] HRM indicated that it supports the proposal put forward by the Consumer Advocate and has also suggested that the following items be included in the Plan:

NSPI direct some resources to provide electronic data interchange (EDI) with its largest customers.

NSPI increase the capability of its Smart Meter program to increase the timeframe for available data.

If the DSM Program is to be administered by NSPI, consideration should be given to it being administered by the Generation group and not by Marketing & Sales.

(HRM, Redacted Closing Submission, p. 16)

[458] Dr. Larry Hughes, a professor at Dalhousie University, filed Direct Evidence and a Closing Submission. He recommended against Board approval of the Plan. It is his opinion that the most cost effective way to use the funds is to initiate a program of demand reduction, EnerGuide for house renovations/new construction, and promotion of conservation and energy efficiency. He suggested that the following recommendations could form an alternative DSM program:

> - More of the funds should be devoted to demand reduction: this means a CFL programme that targets those on low-and fixed-income first, replacing all bulbs (those involved in last year's Keep the Heat programme are apparently pleased with them). If $4 million were devoted to this at $4/bulb, 1 million bulbs could be purchased and installed.
>
> - The EnerGuide for Houses programme element should be increased to $520,000 (to include audit costs) and targeted at those on low-and fixed-income who use electric heating.
>
> - The remaining $480,000 should be used to promote conservation and energy efficiency; for example, through advertising campaigns encouraging customers to use less electricity during peak periods.
>
> (Dr. Hughes, Redacted Closing Submission, p. 9)

[459] The Province argued that the Plan provides sufficient details and was developed by input from stakeholders, including feedback from a consumer forum held by NSPI. It is the Province's view that the Plan should be approved with the following modifications:

> 56. Dr. Stutz and Ms. Brockway have suggested that some formal DSM consultant should be involved at the outset. The Province supports the stakeholder driven process that NSPI has undertaken at this stage. The Province believes that, following the initial implementation of NSPI's DSM plan, an independent assessment of the first year's results should be undertaken by a consultant specifically retained for that purpose, to ensure that the DSM program is on track.
>
> (Province, Redacted Closing Submission, p. 24)

[460] The Province also submits that, in case the Board decides not to approve the Plan, it supports partial approval of funds to retain an outside consultant to complete the Plan.[163]

[461] The Nova Scotia NDP Caucus made a presentation to the Board at the evening public session, and submitted a petition signed by approximately 32,563 citizens of Nova Scotia. The petition requested that there be no increase in electricity rates until NSPI and the Province assist the customers of NSPI to save at least 15% on their electricity bill.

[462] The NDP Caucus has indicated that it would like to see further scrutiny of the Plan in a separate hearing in 2006:

> For the NDP, one of the central issues regarding DSM are the intentions of the Board respecting further scrutiny of the issue in detail, as a follow up to the 1992-93 set of hearings and the Board's 1996 discussion of Integrated Resource Planning on DSM in its rates' decision. Our request is that the Board move to convene a separate set of DSM hearings at an early date, certainly some time in 2006.
>
> (NDP, Redacted Closing Submission, p. 9)

[463] SEB, in its Closing Submission, expressed concern about the timing of the submission of the Plan, stating that the Plan did not provide sufficient time to review and cross-examine the Company. SEB also questioned the allocation of DSM costs to below-the-line customers, especially ELIIR customers. SEB's recommendation is that a separate and more focused DSM proceeding be held before the Board approves the Plan.

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[163] Province, Redacted Closing Submission, para. 57

[464] The Nova Scotia Liberal Caucus, in its Closing Submission, noted that NSPI needs to do more in its Plan to provide real reductions in energy use. It is their view that consultation with professionals in this field is required to achieve the desired results.

[465] Dr. Stutz described his opposition to the Plan as follows:

> ... NSPI has included five million in required revenues to fund its conservation and energy efficiency plan for 2006. The plan was filed on November 7 as part of the company's rebuttal. The plan is 54 pages in length. It contains large amounts of data, and the results of technical analyses. Work papers explaining and supporting the plan have not been filed. There has been no opportunity for parties to submit information requests on the plan or to address it in their evidence. In 2004 and 2005, NSPI spent about five hundred and fifty thousand dollars ($550,000) on energy efficiency and conservation. The 2006 plan calls for a roughly tenfold increase. A thorough review is appropriate. This can best be accomplished through a separate hearing to be held early in 2006. Until such a hearing is held, there is no reasonable basis for approving funding for the 2006 plan. Funding for energy efficiency and conservation at the level of 2004/2005, that is, five hundred and fifty thousand dollars ($550,000), should be approved now to permit work on conservation and energy efficiency to continue. In its decision and order in the hearing just mentioned, that is, the hearing to be held in early 2006, the Board could authorize additional spending in 2006 on the 2006 plan, subject to deferred cost recovery if that proves appropriate.
>
> (Transcript, December 2, 2005, pp. 3511-3512)

7.1.4 Findings

[466] The Board has considered all the evidence provided during the hearing including the comments expressed at the public sessions on November 23-24, 2005, and final submissions.

[467] The Board has reviewed the DSM Plan submitted by NSPI and commends its effort in preparing the Plan, including conducting deliberative polling, forming a stakeholders committee and seeking customer input at the Company’s customer forum. All intervenors and consultants generally agree that DSM is important and that it ought to be pursued. However, most of them have raised issues with the lack of analysis in the

Plan and its late filing. The Plan was filed with the Board as part of NSPI's Rebuttal Evidence on November 8, 2005, and proposes an increase of $5 million annually, a tenfold increase over the current level of spending on DSM.

[468] The Board understands that the Company's request is for the approval of an additional $5 million annually, but it is not seeking approval of the details of the Plan as submitted. Board Counsel clarified this issue during cross-examination of NSPI's witnesses:

> Q. Just to follow up on that point of clarification by Mr. Gallant that NSPI is looking for approval of the budget but not approval of the plan, what control does the Board have over the spending of that $5 million dollars if the plan elements are not vetted and approved?
>
> A. (Tedesco) For this hearing we've put forth our proposal. Upon listening to stakeholders and participants in this hearing, the Board can clearly decide what it thinks is in the best interest of our customers and how best to invest that money.
>
> Q. But you're not looking for approval of any specific plan elements?
>
> A. (Tedesco) The plan represents our recommendation, and as was said a moment ago, we're really looking for input from customers. We sought to put forward a specific plan that identified how we might invest the money based on what we heard or what we thought we heard from customers. We also recognize the Board may have other interests and perspectives that need to be considered, and I would view it as really no different than any other investment of this magnitude that the company might undertake.
>
> THE CHAIR
>
> Excuse me, Mr. Tedesco. How does that differ from if the Board requests -- if NSPI requests the Board to approve a capital expenditure, how do you see the difference between that and this scenario?
>
> MR. TEDESCO
>
> I think the analogy is quite similar, that I would view this in a similar sort of way, that it's a significant amount of money, the company in the case of a capital expenditure would put forward a plan, the Board may have questions about it, the plan may be modified as a result of information that is discussed and provided to the Board, and we understand that and I would look at that as the normal course of events.
>
> THE CHAIR
>
> But the Board would normally approve the capital expenditure after reviewing the economic scenarios, et cetera.

MR. TEDESCO
That's right.

THE CHAIR
But you're not asking in this case the Board to approve this particular plan?

MR. TEDESCO
We're not asking that this specific plan be approved, we're simply seeking to demonstrate that we've put forward -- now we have given some thought to how we would propose investing this money. We also recognize that others may have different opinions.

(Transcript, November 16, 2005, pp. 517 - 519)

[469] A number of intervenors have argued that the Plan was submitted too late in the process, and they did not have sufficient time to review and prepare their evidence in relation to it. They assert that the Plan contains technical information and required input from their experts, who did not have sufficient time due to the Plan's late filing.

[470] The Province, however, supports the Plan on the basis that the Company has followed a stakeholder driven process and that the Plan provides sufficient details for approval by the Board. The Province is recommending approval along with an independent review by an outside firm after the first year of implementation to confirm whether the Plan is on track. The Province has also stated in its Closing Submission that, in the event the Plan is not approved, the Board approve funds to retain an outside consultant to finalize the Plan.

[471] Ms. Brockway opposes the Plan, but recommends approval of $550,000 to retain an outside consultant to finalize the Plan. It is also her view that there are additional opportunities which need to be explored, and which could be more effective than those proposed in the Plan.

[472] Dr. Stutz testified that the Board should approve additional funds in the amount of $550,000. When cross-examined by Mr. Connors, he explained that this amount would keep "... the design and development process moving, and it's out of that that I would expect the consultant and other activities to be funded."[164]

[473] The Board, having considered all the evidence, agrees that approval of the Plan, as submitted by NSPI, is premature at this time. Clearly, the Plan needs additional design work and resources. It is important that DSM move forward, but not without regard to its cost effectiveness. NSPI customers expect that any DSM program will be carefully designed to ensure its maximum impact, and that it is effectively implemented. The Board concurs with Ms. Brockway and Dr. Stutz that a DSM program requires expert input. Accordingly, the Board approves $550,000 in additional funds (and not the $5 million requested by NSPI) to retain an outside consultant and to complete the Plan's design and development.

[474] NSPI is directed to prepare the terms of reference for the consultant and submit them to the Board for approval no later than April 15, 2006. The terms of reference shall contain the procedures for identifying and selecting the consultant who will assist NSPI in the finalization of the DSM Plan. The process of retaining and selecting the consultant will be monitored by the Board.

[475] A number of intervenors have raised the issue as to whether NSPI should be implementing the Plan. This is based on their view that the Company may be in a conflict

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[164] Transcript, December 2, 2005, p. 3566

of interest position since its business involves the generation and selling of electricity, and pursuing its shareholder interests. The objectives of DSM are demand reduction and energy efficiency, which may conflict with the Company's mandate (i.e., sell more electricity). The Board does not have a view on this issue at the present time and directs that it be part of the mandate of the outside consultant, and that appropriate recommendations be included in that consultant's report.

[476] The Board has considered the suggestion from intervenors that a separate hearing be held on DSM in 2006. NSPI, however, has stated that enough input has been received from its customers and stakeholders with respect to the types of programs they desire, and their anticipated impact. The Board agrees that insufficient time was afforded to intervenors to fully review and evaluate the Plan. In addition, given the resources and time required to allow a fair review, a separate hearing on DSM is appropriate. The Board orders that a separate hearing on DSM be held in the second half of 2006.

[477] The Board understands that to start the hearing process, the Plan needs to be finalized. The Board orders that NSPI complete the Plan and file it with the Board no later than June 30, 2006, utilizing the assistance of the Board approved consultant.

8.0 DEPRECIATION

8.1.1 Submissions - NSPI

[478] NSPI, in its application, forecasts depreciation expenses of $128.8 million for the 2006 test year. This increase is explained by the Company as follows:

> Depreciation expense has increased by $9.0 million to $128.8 million between 2005C and 2006. The increase principally results from:
>
> - The continued phase in of revised depreciation rates previously approved by the Board. The 2006 test year revenue requirement is calculated based on the second year of the four year phase-in of depreciation rates approved by the Board in its Decision dated November 21, 2003 in NSUARB-NSPI-P-879.
> - Capital additions approved by the Board since December 31, 2004.
>
> (Exhibit N-1, p. 106)

[479] The proposed depreciation expense also includes year two of the four year phase-in of new depreciation rates which is estimated at $6.6 million.

> The UARB approved the Settlement Agreement (Decision dated November 21, 2003, and Order dated December 23, 2003, in NSUARB-NSPI-P-879) and ordered an increase in depreciation rates for NSPI's depreciable property. As unanimously agreed by all parties, the Board directed that the increase in depreciation rates would be phased in over four years in equal instalments commencing January 1, 2004. In its decision in the 2005 Rate Application, the UARB deferred the phase-in by an additional year. This reduced the 2005 revenue requirement by $6.0 million.
>
> (Exhibit N-1, p. 106)

8.1.2 Submissions - Intervenors

[480] The Municipal Electric Utilities of Nova Scotia Co-operative, the only intervenor to express a view on this issue, is of the opinion that the postponement of the second year of the four year depreciation rates phase-in is more appropriate this year than last year, given the proposed increase in rates:

> If this was appropriate in a 12.4% increase world (NSPI's request for 2005 rates) surely it is even more appropriate for the 2006 proposal of 14.7%. Depending on future rate increase requirements for 2007 and 2008, how this phase-in is to be finally accomplished should be reviewed once these are known. Delaying the year 2 phase-in again will reduce the additional revenue requirement by some $6.6 million (NSPI Direct Evidence Pg. 107 line 3).
>
> (MEUNSC, Redacted Closing Submission, p. 4)

8.1.3 Findings

[481] In the 2005 rate decision, the Board deferred, for one year, the second year of the four year phase-in of the increases in depreciation rates. The deferral was based on the proposed increase in rates and potential rate shock to customers.

[482] In the present application, the Company is proposing an average rate increase of approximately 13% (modified from 14.79% after the natural gas settlement). In the 2005 rate case, the proposed average rate increase was 12.4%. The Board was concerned about the size of proposed increases and rate shock impact on customers. The Board is faced with a similar dilemma this year.

[483] NSPI, in its closing submission, argues that currently there is a shortfall of about $35 million in depreciation expenses, and that any further postponement will add additional expense to the customers:

> During its March 31, 2005 decision, the UARB delayed the phase-in by one year and some intervenors have suggested through their questions in this rate proceeding that an additional deferral may be appropriate. Based on the most recent depreciation study, annual depreciation expense is at least $35 million less than it should be. As the UARB believes more timely depreciation studies should be carried out (and were in fact carried out), then it should be prepared to accept the increases in depreciation expense that were determined. Otherwise the exercise adds additional expenses without any actionable response. Appropriate recovery of capital expense is not only essential from a cash flow perspective but

> also important component in raising capital to finance the significant capital requirements that NSPI will face over the balance of the decade.
>
> (NSPI, Redacted Closing Argument, p. 84)

[484] The Board appreciates the concern expressed by the MEUNSC with respect to the proposed rate increases and their impact on the customers. The Board, in the 2005 rate decision, deferred the second year phase-in of the four year increase in depreciation rates for one year on the understanding that the increase would be resumed in the following year. The Board is also mindful of the issue raised by NSPI that the new depreciation rates should be in place before major upgrades to the generating stations are completed and become part of the Company's depreciable assets.

[485] The Board, having considered all the evidence, approves the resumption of the four year phase-in of depreciation rates in the 2006 test year.

9.0 RATES

9.1.1 Overview

[486] This section deals with the process to determine customer rates based on the Board's approved revenue requirement for NSPI. The revenue requirement approved by the Board is lower than that applied for by NSPI, making the resulting rates lower than those proposed by the Company. NSPI is directed to incorporate these changes and submit a Compliance Filing for the Board's approval.

[487] NSPI customers fall into two categories, above-the-line ("ATL") and below-the-line ("BTL") or Annually Adjusted Rates ("AAR"). BTL rates are adjusted annually based on pre-defined methods or existing agreements. NSPI normally makes an application to the Board no later than November 1 for approval of rates effective January 1 of the new year.

[488] ATL rates, on the other hand, are only changed by the Board upon application by the Company, and after a full public hearing. Otherwise, they remain the same indefinitely.

[489] The rate changes for all above-the-line (ATL) rates are to be effective March 10, 2006, and the rate changes for all the below-the-line rates are to be effective January 1, 2006.

10.0 ANNUALLY ADJUSTED RATES/BELOW-THE-LINE RATES

10.1 Overview

[490] NSPI submitted its proposed 2006 AARs for approval on August 5, 2005, earlier than the normal November 1 filing date. NSPI described the reason for the earlier filing as:

> ... This is in order to provide the opportunity for full review in conjunction with NSPI's 2006 Rate Application filed with the Board on June 28, 2005, and to enable the rates to be in effect as of January 1, 2006, the normal effective date for AARs.
>
> (Exhibit N-155, August 5, 2005 letter)

[491] NSPI currently has the following AARs available for its customers:

- Mersey System Rate[165]
- Generation Replacement and Load Following Rate (GRLF)
- One-Part Real Time Pricing Rate (1P-RTP)
- Two-Part Real Time Pricing Rate (2P-RTP)
- Extra Large Industrial Interruptible Rate (ELIIR)

10.2 Generation Replacement and Load Following Rate

[492] The Generation Replacement and Load Following Rate ("GRLF") is designed to provide load following and back up service to large customers who own their own generation facilities or otherwise qualify for the rate. These are two separate rates: the Generation Replacement Rate is used in case of interruption to the customer's own

[165] The Mersey System Rate is governed by a separate contract.

generation, and the Load Following Rate is used for additional load required by the customer above its own generation capacity.

10.2.1 Submissions - NSPI

[493] NSPI proposes a 2006 Load Following Rate of $71.60/MWh compared to the 2005 rate of $61.60/MWh.[166] NSPI states that this rate has been computed using the Strategist model to compare a "base case" with a "25 MW decrement case" as in previous years plus a $5/MWh adder. NSPI submits that the reasons for the increase are:

- increases in heavy fuel oil and natural gas prices
- a higher percentage of the time when the marginal cost is determined by oil or gas fired generation

[494] The Generation Replacement Load rate is to be calculated similar to previous years as a sum of a $5/MWh adder and the actual marginal cost for the period of time under which the customer's generation is out of service.

[495] The GR and LF rates are calculated based on the assumption that there is no export of electricity from the system.

10.2.2 Submissions - Intervenors

[496] The Board did not receive any submission commenting specifically on the GRLF rate.

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[166] Exhibit N-155

10.2.3 Findings

[497] The Board has not received any evidence in opposition to NSPI's proposed GRLF rates and they have been calculated as in previous years. Accordingly, the 2006 GRLF rates proposed by NSPI are approved by the Board effective January 1, 2006.

10.3 Real Time Pricing Rate (1P-RTP)

10.3.1 Submissions - NSPI

[498] NSPI has three "one-part" RTP tariffs, one for each of three voltage levels (Extra High Voltage, High Voltage and Distribution Voltage) at which RTP customers may be served.[167] All three tariffs consist of on-peak and off-peak adders set in advance, plus marginal costs as they occur. The Board annually approves adjustments to these adders. NSPI states that the proposed adders have been calculated using the same methodology as in previous years.

[499] NSPI provided the following comparison of the proposed 2006 adders to those approved by the Board for 2005:

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[167] Exhibit N-155, August 5, 2005 letter, p. 4

Comparison of On-Peak Adders				
	On-Peak Adder (Cents/KWh)		Off-Peak Adder (Cents/KWh)	
	Proposed 2006	Approved 2005	Proposed 2006	Approved 2005
Extra High Voltage	6.025	5.416	0.292	0.274
High Voltage	6.027	5.665	0.537	0.527
Distribution	8.359	8.171	2.149	2.102

[500] In addition, NSPI submits that some clarification is required of the demand level to be used to compute the transformer ownership credit in the Extra High Voltage 1P-RTP tariff. The demand level is used in applying the transformer ownership credit when 1P-RTP is used along with ELIIR. NSPI explains that when maintenance is scheduled by the customer and, if the customer remains at the normal peak value for an hour after the maintenance is scheduled to commence, the customer receives an unwarranted discount.[168]

[501] NSPI is proposing to clarify this by adding a sentence (to be inserted immediately following the transformer ownership clause in the Extra High Voltage Time of Use, Real Time Price Tariff) as follows:

> When used with the Extra Large Industrial Interruptible Rate (ELIIR), this credit is to be applied to 1P-RTP demand levels which occur when the customer's ELIIR UET is set at normal, and not reduced levels as during shutdown periods as permitted under the ELIIR tariff.
>
> (Exhibit N-155, August 5, 2005 letter, p. 4)

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[168]Exhibit N-25, UARB IR-16, Attachment 1, p. 27

10.3.2 Findings

[502] There were no intervenor submissions on either the proposed increase in the 1P-RTP adders or the proposed amendment to the tariff. The Board approves the adders and the tariff addition proposed by NSPI to be effective January 1, 2006.

10.4. Two Part Real Time Price Rate (2P-RTP)

[503] The Two Part Real Time Price (2P-RTP) Rate was first approved by the Board in its decision dated November 21, 2003, at the request of NSPI and its customers. The rate was to be initially available to users of the Extra Large Industrial Interruptible Rate (ELIIR) and later to users of the Large Industrial Rate. The Board understands that so far this rate has only been used by ELIIR customers.

10.4.1 Submissions - NSPI

[504] NSPI, in its application, has indicated that the two ELIIR customers are expected to take load under 2P-RTP in 2006. The actual load for 2006 was uncertain, but NSPI has assumed sales of 218 GWh and estimated revenues of $13 million in calculating rates for 2006. The average net rate for 2P-RTP is expected to be $60.80/MWh.

[505] NSPI is also proposing a tariff wording change to address an item identified by NSPI in its July 11, 2005 status report to the Board on AARs.[169] The issue concerns the amount of economic interruption permitted under the ELIIR tariff when a customer uses

[169] Exhibit N-25, UARB IR-16

ELIIR in combination with 2P-RTP. The amount of economic interruption is determined by the amount of operational Tariff Demand (where Tariff Demand is the amount of load subscribed to under the ELIIR tariff) which can be at a lower value than the Tariff Demand used to compute the customer's alternative cost.

[506] It is NSPI's position that, by setting a lower Tariff Demand for operational use, the customer is able to partially escape the obligation to interrupt but keeps the economic benefit of ELIIR pricing.[170] This means a loss to NSPI in terms of its ability to avoid some of the high cost combustion turbine production and these costs then have to be reflected in the revenue requirement for ATL customers. NSPI's proposed solution is to add back these financial costs into the 2P-RTP tariff calculations, thereby charging them to the ELIIR customers.

[507] NSPI proposes that the following wording be added to the "Forecast ELIIR Cost (FEC)" section of the 2P-RTP tariff:

> When a customer utilizing the ELIIR in combination with 2P-RTP nominates a UET_{OP} that is different than the $UET_{CAC,}$ the difference between these UETs (ie: a modified TD) is to be multiplied by the ELIIR economic interruptibility (EI) factor (ie: 0.31 GWh/MW) to determine the change in the quantity of EI energy available. This energy quantity is to be multiplied by the average CT/High Cost Import unit cost (ie: $/MWh) forecast for the year in which the rate will be in effect, to determine the value of the modified EI. This dollar value is then to be subtracted from the FEC to determine a "TD Adjusted FEC" for use in determining the CBLbc required.
>
> (Exhibit N-155 and modified by NSPI response to SEB IR-151)

[508] NSPI states that 'net cost' here means the average cost of CT/High Cost Import less the CBL base rate for energy.

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[170] Exhibit N-25, UARB IR-16, Attachment 1, p. 26

[509] NSPI stated in its Rebuttal Evidence that it is not proposing to increase the revenue from 2P-RTP, but is merely seeking to achieve the revenue provided by the approved 2P-RTP rate. NSPI explained the issue further as follows:

> This issue revolves around Special Condition 3 of the 2P-RTP Tariff. Special Condition 3 was added to the tariff at SEB's request on the morning of the Hearing at which it was reviewed. NSPI required that the last sentence of this clause be added as a result of this last-minute change to the tariff proposed by SEB. In fact the Hearing was delayed for some time while these negotiations were held.
>
> SEB proposed that the annual quota defining how much energy could be interrupted by NSPI for economic reasons should be calculated using the lower UET_{OP} and not the UET_{CAC}. NSPI recognized that this would result in a reduced availability of economic interruption while at the same time providing a reduced rate to the 2P-RTP customer that would have required a higher level of interruptibility. In order to ensure that ATL customers did not pay more as a result of this, NSPI requested the inclusion of the last sentence of Special Condition 3 which requires that any adjustment of the UET_{CAC} not undermine the value of ELIIR or the three principles which underpin 2P-RTP. NSPI has applied the 2P-RTP tariff consistent with Special Condition 3, requiring 2P-RTP customers to pay for the reduced availability of economic interruptibility in exchange for the lower rate they are provided when they reduce the UET that was used to develop the original CAC rate.
>
> NSPI is not proposing to change the 2P-RTP tariff. The Company is seeking to modify the wording of the tariff to more clearly state the original intent of special condition 3.
>
> (Exhibit N-153, pp. 105 -106)

10.4.2 Submissions - Intervenors

[510] SEB presented evidence from Dr. Rosenberg on the 2P-RTP rate. Dr. Rosenberg does not agree with NSPI's proposal to change the tariff. In his evidence he states:

> ... In the first place the 2P-RTP tariff was meticulously crafted after very extensive negotiations and much give and take on both sides, and with the active assistance of Dr. Stutz. The tariff, which was agreed to by all parties and approved by the Board, explicitly states that:
>
> - The TD_{op} can be, and indeed must be, different than the TD_{CAC}.
> - The RTP energy is not subject to economic interruption
> - No extra charges are contemplated for these imaginary economic interruptions.

> In the second place, NSPI's proposal, if adopted would literally destroy its touted RTP program before it has even been allowed to begin.
>
> (Exhibit N-91, p. 35)

[511] Dr. Rosenberg explained his reason for stating that the 2P-RTP program would be destroyed by providing a computation showing that by switching from ELIIR/2P-RTP to the Large Industrial Interruptible Rate (LIIR), the total charges for a hypothetical customer would be lower under LIIR than under EIIIR/2P-RTP with NSPI's adjustment, plus the customer would not have to incur either economic or priority supply interruptions.

[512] SEB states that:

> NSPI's position on this matter is, with respect, without foundation. As Dr. Rosenberg makes plain in his evidence, both the words of the Tariff and the underlying purpose of the RTP program belie the validity of NSPI's position.
>
> (SEB Submission on Non-Fuel Matters, p. 27)

[513] SEB computes (using the NSPI response to SEB IR-151) that, for the 250 MW load of SEB, the language change proposed by NSPI would result in the customer paying $5.75 million more annually.

[514] SEB requests that the Board clarify that SEB's interpretation of the tariff is correct or, alternatively, reject NSPI's proposal and allow the parties to bring the matter before the Board to argue the issue in a full and complete manner.

10.4.3 Findings

[515] The Board has considered the evidence of NSPI and SEB and understands that the issue is intertwined between the 2P-RTP and ELIIR rates. It is also the Board's

understanding that only ELIIR customers have signed on for the 2P-RTP rate as of the date of hearing.

[516] The Board, for reasons set out later in this decision, has ordered a separate hearing on the ELLIR rate or its successor rate, to fully review the impact of the current situation on the Company and the ELIIR customers.

[517] Special Condition 3 of the 2P-RTP tariff currently reads as follows:

> In the event that the ELLIR rate (with or without 1P-RTP) is used to calculate the Customer's Alternative Cost (CAC), the UET rather than the UET $_{(CAC)}$ will define the level of economic interruption. The UET will be set at a level which will not undermine the value of ELIIR or the three principles which underpin the 2P-RTP.

[518] Special Condition 3 refers to three principles which underpin the 2P-RTP. The three principles are set out in the Board's decision dated August 1, 2003.[171] The Board stated that:

> [143] NSPI's proposed changes to the RTP rates were the subject of discussion prior to and during the hearing in an effort to reach a consensus on an acceptable set of RTP rates. While a specific rate design was not agreed upon, NSPI, SEB and Dr. Stutz, agreed to continue discussions and attempt to develop a rate for presentation to the Board during the next general rate case. This agreement was set out in Exhibit N-22 and reads as follows:
>
> > Nova Scotia Power/Bowater Mersey/Stora Enso/Dr. John Stutz
> >
> > Statement Regarding RTP
> >
> > We have agreed to develop an alternative load shifting rate option, the principles of which are:
> >
> > 1. Under this option the customer who shifts load will never pay more than the customer would have paid under the customer's real alternative rate.
> >
> > 2. The rate will be the customer's best option without shifting, less the value to NSPI of the shift.
> >
> > 3. Above the line customers will be kept whole.

---

[171] NSUARB NSPI-P-878

The parties will continue their discussions and ask the Board not to make a final decision on RTP issues pending the presentation by NSPI of a specific proposed rate option in the next general rate case consistent with these principles.

6.4 Findings

[144] The Board notes that the evidence presented during the hearing focused on the problems associated with the RTP rate. The Board concludes that there are no major concerns with respect to the price signals associated with the other below-the-line rates and, therefore, no modifications to other rates are required at this time. The Board recognizes that there were a variety of concerns presented with respect to the RTP rate and it appears clear that the rate, as presently structured, does not function as intended.

[145] The Board is satisfied that the principles set out in the above Statement form a suitable basis for the development of an acceptable RTP rate design. Accordingly, the Board agrees to defer the RTP rate design issue until the charges for the ELIIR are approved. It is the Board's understanding that the parties will continue to work towards reaching a consensus on the RTP rate design. The Board also agrees with the comments of several Intervenors, who were not involved in the negotiations resulting in the Statement, that "...the next round of RTP discussions involve all existing and former RTP customers, potential new RTP customers and any interested stakeholders". The burden will, of course, be on NSPI to justify its proposed rate to the Board.

(Board Decision, Generic Rate Hearing, August 1, 2003, para. 143-145)

[519] The Board had a follow up hearing in October/November 2003 to consider approval of the Real Time Price Rate Design, AAR's for 2002, 2003, 2004 and ELIIR charges for 2004.

[520] The Board, in its decision dated November 21, 2003[172], noted the process followed by NSPI and intervenors to achieve a unanimous agreement on these issues:

[12] Following a series of meetings between NSPI, SEB and Dr. Stutz, NSPI filed revised Supplementary Evidence (Exhibit N-26), dated November 3, 2003, which outlines a settlement agreement between the parties with respect to the AARs and the development of a new 2P-RTP which would operate in addition to the existing RTP (1P-RTP) rates and provide greater flexibility for customers.

[13] At the hearing on November 4, 2003, Mel Whalen, Director of Regulatory Affairs and Rates for NSPI, read into the record an agreed-upon revision to Appendix A-1 of Exhibit N-26. Mr. Whalen confirmed that Exhibit N-26, with the revision noted, constituted the final

[172] NSUARB-NSPI-P-879

settlement agreement with respect to AARs for the period in question, and the new 2P-RTP. The settlement agreement, including the revision noted by Mr. Whalen, is attached in its entirety as Appendix C to this decision. NSPI also advised that 2P-RTP component of the settlement agreement conforms to the three principles endorsed by the Board in its August 1, 2003 decision on Generic Rate Design, *supra.*

[14] According to Exhibit N-26, the parties agree on the main points of contention with respect to the 2P-RTP, namely the methodology used to establish the Customer Baseline Load ("CBL") and the issue of exports. Further, NSPI's evidence states that:

> NSPI would note that while the proposed settlement agreement was partially arrived at on an issue by issue basis, it was, for the most part, developed as a total package which results in adjustments to both the 2P-RTP proposal and certain of the AAR's.
>
> The issues addressed by this settlement agreement with respect to the AAR's primarily impact 2003 and 2004, neither of which is expected to be a rate case year. The proposed settlement, and its associated financial impact therefore, will not affect any above-the-line customers.

[15] The highlights of the settlement agreement, with respect to the new 2P-RTP, include allowing the customer to propose alternative methods of developing an Annual Hourly Load Shape ("AHLS"), and the CBL, with the burden on the customer to show the resulting AHLS and CBL are reasonable; eligible customers must choose either the 1P-RTP or the 2P-RTP; use of a twenty-minute ahead forecast of system marginal costs, excluding electricity export impacts; and the inclusion of a provision for export margin sharing.

...

[17] Dr. Stutz filed evidence dated October 20, 2003 and October 24, 2003 (Exhibits N-27 and N-28) concerning his recommendations for the AARs and the proposed 2P-RTP. He also gave evidence at the hearing regarding his support for the settlement agreement, as revised. His opening statement (Exhibit N-29) states as follows:

> NSPI and SEB have reached an agreement ("the Settlement") which provides a Two-Part Real Time Price (2P-RTP) rate design and resolves all of the issues related to the Annually Adjustment Rates (AAR's). I participated in the negotiations which led to the development of the Settlement. In my view, the Settlement provides a reasonable resolution of the issues raised in this proceeding for all years through 2004. I urge the other parties to support the Settlement, and the Board to adopt it in its Decision and Order.
>
> The Settlement addresses the issues raised in my evidence and resolves them in a reasonable fashion:
>
> • For the 2P-RTP rate, I recommend adoption of NSPI's proposed rate design with six changes. The settlement adopts NSPI's proposal with all of my changes.

- While the Incremental Export Benefit credit differs in formulation for my proposed Export allowance, it is reasonable. The 15% cap provides a benefit to other ratepayers absent in my proposal.

- I recommended that exports be excluded when calculating GRLF, IEIR and ELIIR charges. The Settlement incorporates this change for 2003, and 2004.

The three points just listed address the major concerns raised in my evidence. The Settlement also provides for a downward adjustment of approximately [$]800,000 to the Mersey and IEIR rates. This adjustment settles a number of remaining issues including items b), c), and d) listed in Appendix B of NSPI's supplemental Evidence. Based on my participation in the negotiations, I believe that such an adjustment was the only way to settle these issues, and that the result produced by the adjustment is reasonable. In particular, without any admission by NSPI or any finding against NSPI on the merits, the adjustment addresses the 2002 AAR's and the interruptible load for 2003 in a fashion consistent with my evidence on these matters. Based on my review of all the issues in this proceeding, including those raised by Dr. Rosenberg in his evidence concerning the 2004 AAR's, I believe the adjustment, together with the other parts of the Settlement, produces a reasonable result.

[18] Those Intervenors who participated in the AAR and RTP rates phase of the proceeding confirmed to the Board that they agreed with the settlement proposal negotiated between NSPI and SEB, with the assistance of Dr. Stutz. Those supporting the agreement include ECANS, CME, MEUNSC, the Province and Quetta. While every Intervenor to the proceeding as a whole is not included in this group, all those Intervenors present for the AAR and RTP phase of the hearing did indicate their support for the settlement.

(Board Decision, November 21, 2003, para. 12-18)

[521] The Board approved the unanimous agreement submitted by all parties and concluded that:

FINDINGS

[19] The Board has carefully reviewed all the evidence presented with respect to the AARs's and RTP rates in this proceeding. The Board particularly notes that those Intervenors, including ECANS, CME, MEUNSC, the Province and Quetta, who have an interest in these matters, support the settlement agreement. The Board also notes that Dr. Stutz, who independently reviewed the agreement, is satisfied that the agreement represents "... a reasonable result." As is the case with the agreement on depreciation, the Board notes that, in the absence of a general rate application, this agreement has no impact on rates for above-the-line customers. The Board also is aware that the agreement achieved is the result of an extensive consultation process between NSPI and the below-the-line customers who are potentially impacted by the adjustments, together with input from Dr. Stutz.

...

> [22] These comments apply equally to this phase of the hearing. In view of the support of the agreement by those Intervenors with an interest in this phase of the hearing, and in view of the evidence of Dr. Stutz, the Board is satisfied that the proposed methodologies for calculating and applying the AARs and the 2P-RTP are fair and reasonable. Accordingly, the Board finds it is both reasonable, and in the public interest, to approve the settlement proposal. The Board accepts the settlement proposal as outlined in Exhibit N-26 and revised by Mr. Whalen (Appendix C), and approves, in principle, the revisions to the AARs and the proposed new 2P-RTP which will result from the application of the revised settlement agreement to the formulation of these rates.
>
> (Board Decision, November 21, 2003, para. 19-22)

[522] The Board understands that NSPI's proposed addition to the 2P-RTP tariff is to satisfy the third principle of the 2P-RTP design that "above the line customers will be kept whole". SEB, on the other hand, is suggesting that if the proposed addition is approved, the cost to ELIIR will rise.

[523] The Board has reviewed its previous two decisions, noted above, in which the 2P-RTP was approved. It is the Board's view that the three principles under which this rate was approved and, unanimously supported by all parties, clearly state that the above the line customers are to be kept whole.

[524] The language in the current 2P-RTP tariff was the subject of detailed discussion. It was supported by both NSPI and SEB when originally implemented.

[525] The Board has decided that ELIIR will be substantially redesigned for 2007. The redesign will affect the 2P-RTP rate used in conjunction with ELIIR.

[526] In light of the unanimous support for the language in the existing 2P-RTP rate and the likelihood of substantial change effective January 1, 2007, the Board has decided not to approve any changes in the tariff wording at this time. The Board approves the 2P-RTP rate in its current form effective January 1, 2006.

10.5 Extra Large Industrial Interruptible Rate (ELIIR)

[527] ELIIR was first approved by the Board in 2003[173] and is available to large industrial customers who have a service voltage of at least 138 kV, and are subject to supply interruptions and economic interruptions as per the Board approved tariff.

[528] SEB is proposing a new BTL rate, known as the FP-DSM/DR rate, as defined below, to replace the ELIIR rate. The new rate is described as being cost-based.[174] Dr. Stutz is proposing that for 2006 an interim ELIIR rate be approved based on the LIIR with credit for economic interruptibility and that the Board hold a hearing in 2006 to approve a new BTL rate, which will be a successor to ELIIR.

10.5.1 Submissions - NSPI

[529] NSPI proposes that, for the period January 1, 2006 to December 31, 2006, the ELIIR monthly customer charge be set at $24,100 and the energy rate be set at $60.80/MWh, assuming an 85% load factor level.[175] NSPI states that the customer charge and energy rate have been calculated using the original formula approved by the Board in 2003, and that the resulting increases are driven by higher fuel costs.

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[173] NSUARB-NSPI-P-877

[174] Exhibit N-61, p. 14

[175] Exhibit N-155, August 5, 2005 letter, p. 5

[530] NSPI also states that, if ELIIR customers provided accurate hourly demand forecasts on a day ahead basis, benefits would accrue to all customers. NSPI requests that the following Special Condition 5 be included in the ELIIR tariff:

> The customer shall, by 10 am each day, provide NSPI's operations personnel with accurate hourly demand forecasts on a day-ahead basis. These forecasts will provide ongoing 168 hour (7 day ahead) energy requirements. The customer is to alert NSPI of any known changes to this forecast with a minimum of three hours advance notice on the day such changes are required.
>
> (Exhibit N-155, August 5, 2005 letter, p. 5)

[531] NSPI responded to the Forest Product-Demand Side Management - Demand Reduction ("FP-DSM/DR") rate (described below) proposed by SEB as follows:

> The rate proposed by Bowater Mersey Paper Company and Stora Enso Port Hawksbury Limited (respectively 'BMPC" and "SEPH" and collectively "SEB") is not cost based. The rate produces less than the cost of service and provides less BTL revenue.
>
> In order to maintain recovery of the necessary revenue requirement if SEB's rate proposal is accepted, the revenue shortfall must pass to other customer classes. NSPI's estimate of the shortfall in revenue from BTL rates plus associated increases to fuel costs that would result, is an increase to ATL classes of approximately $33-35 million.
>
> Given the legislative entitlement of NSPI to recover its cost of service, approval of the SEB proposal requires the Board to determine if it is appropriate to approve a rate that provides for such an increase to other rate classes. NSPI expects that other customers and stakeholders will have comment for the Board to consider in making this decision.
>
> (Exhibit N-88, pp. 1-2)

[532] Board Counsel explored NSPI's position on what "standard" it used to determine if BTL rates have met the cost of service test. The following exchange occurred during his cross examination of the NSPI's rates panel:

> Q: Now, just turn to page 2, if you would, under Item 2, "Cost of Service," the second paragraph, and this has been restated a number of times in various ways both in your evidence here and in other parts of the pre-filed. It says:
>
> > "The proposed SEB rate would not recover the associated cost of service."

And as I understand it– and we discussed this previously–when you say "cost of service" in the context of this rate, you're talking about the cost of service reflected in the formula?

A: (Boutilier) Yes, and the inputs to that formula which are—

Q: And the inputs to that formula.

A: (Boutilier) ---- based on cost, yes

Q: And that's always the standard that you're referring to when you talk about cost of service and costs being shifted to other customers?

A: (Boutilier) Yes, there are very explicit costs in that formula and NSPI's projection of those costs for 2006 are used explicitly.

(Transcript, November 15, 2005, pp. 367-368)

[533] NSPI addressed both the FP-DSM/DR rate and Dr. Stutz's proposed new rate to replace the current ELIIR in its Closing Argument. NSPI argued that it has computed the 2006 ELIIR rate in accordance with the Board approved formula and forecast costs for 2006. Adoption of the FP-DSM/DR rate as proposed by Dr. Rosenberg is not cost based and would result in the transfer of $33 to $35 million to ATL customers.[176]

[534] As to Dr. Stutz's proposed new rate (see discussion below), NSPI states that it is an inadequate compromise between the ELIIR rate computed by NSPI and the SEB proposal. It would require ATL customers to pay an additional $13.1 million.[177] NSPI referred to Dr. Stutz's statement in which he is proposing "to make an adjustment on an admittedly somewhat ad hoc basis to get a result which I believe is reasonable for 2006."[178] NSPI stated that this ad hoc proposal violates many of Bonbright's principles of a sound rate structure and urged the Board to reject the proposed rate.

[176]NSPI, Redacted Closing Argument, p. 79

[177]NSPI, Redacted Closing Argument, p. 80

[178]Transcript, December 2, 2005, p. 3559

[535] NSPI also recommends that the Board should direct that a proper process of rate design making take place for ELIIR and 2P-RTP in 2006.[179]

10.5.2 Submissions - Intervenors and Dr. Stutz

[536] SEB (Stora and Bowater) are currently the only customers on the ELIIR rate. Witnesses for SEB included Elizabeth Beal, President and CEO, Atlantic Provinces Economic Council, who provided evidence on the importance of the forest industry to the economy of Nova Scotia. Her view is that the forest industry is a vital contributor to the economy of Nova Scotia.

[537] Dr. Rosenberg, on behalf of SEB, filed evidence on September 19, 2005[180], in which he proposed a new rate to replace the ELIIR rate. He also filed evidence on October 17, 2005[181] in which he proposed modifications to the inputs used by NSPI to compute the ELIIR rate.

[538] In addition, Dr. Rosenberg commented on NSPI's proposed Special Condition 5 (day ahead forecasts) for the ELIIR rate, stating that SEB would be willing to make efforts to help NSPI lower its fuel costs in the future, but it would only be fair that it be part of a viable and economic rate.[182]

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[179]NSPI, Redacted Closing Argument, p. 83

[180]Exhibit N-61

[181]Exhibit N-91

[182]Exhibit N-91, p. 37

Forest Product - Demand Side Management/Demand Reduction Rate (FP-DSM/DR Rate)

[539] Dr. Rosenberg describes SEB's reasons for proposing a new rate as follows:

> Both Stora Enso and Bowater find themselves in a precarious position. As the Board is well aware, these two Companies rely on affordable electricity supply to remain economically viable. Effective April 1 of this year, the Board approved a 5.4% increase for the Above the Line classes, but a 10.4% increase for the ELIIR. On July 5, only four months after that Order, NSPI filed a general rate application requesting an additional 14.7% increase for the Above the Line customers for 2006. On August 5, NSPI filed for a 30% increase for the ELIIR rate. In other words if the NSPI application is approved, **SEB will experience a 40% increase from rates that were in effect just 9 months ago**. From almost any perspective, this constitutes rate shock. Obviously, this situation is untenable. The ELIIR rate is not working and so I am proposing a new below the line rate to supplant the ELIIR. [Emphasis added in original]
>
> (Exhibit N-61, pp. 2-3)

[540] Dr. Rosenberg's opinion is that the ELIIR currently does not provide a discount to ELIIR customers that is commensurate with its value to the NSPI system.

[541] He proposes to replace the ELIIR with a new BTL rate; the FP-DSM/DR Rate. The features of the new rate are described by Dr. Rosenberg as follows:

> Q. ARE YOU BASING YOUR PROPOSED NEW BELOW-THE-LINE RATE ON ANY PARTICULAR ECONOMIC DEVELOPMENT OR LOAD RETENTION RATE?
>
> A. No. I have simply pointed out that rates with those specific objectives are not out of the ordinary. However, I believe the new FP-DSM/DR Rate, if such a rate is approved by the Board, should be based on the particular circumstances, history and predicament of the involved customers, NSPI and the province of Nova Scotia, as well as the evidence in this case of course.
>
> Q. WHAT FEATURES ARE YOU RECOMMENDING FOR THE NEW FP-DSM/DR RATE?
>
> A. I am proposing a rate with the following features:
>
> 1. It will be simpler than the current and 2-Part RTP amalgam, hopefully to avoid the controversies and disagreements that have plagued the implementation of those rates. It will also be more flexible than its predecessor.
>
> 2. It will be set for an initial period of a minimum of three years to provide a degree of stability to both the customers on the rate as well

as to NSPI. Thereafter, following the expiry of each three-year period, the rate can be reset either at the request of NSPI or on the volition of the customers on the rate, for a further three-year period. For the first three-year period, this request can be made any time after July 1, 2008, with an effective date of change no later than six months after the request and no earlier than January 1, 2009; and so on for subsequent three-year periods. Any change, of course, would have to be approved by the Board.

3. It will be completely interruptible, for either supply or economic reasons, with 10 minutes notice for supply and 30 minutes notice for economic reasons, but with limitations on frequency, duration of events, and length between events. There is no compensation to the customer for these called interruptions, but the customer can buy through economic interruptions at actual incremental cost plus $5 per MWh. (It cannot buy through supply-related interruptions.)

4. Unlike the ELIIR, which can only be interrupted for avoiding combustion turbines or importing high-priced energy, the FP-DSM/DR Rate could be economically interrupted for any reason, at the discretions of NSPI.

5. At any time, the utility can offer to buy interruptions at whatever rate the utility believes will be attractive to the customer yet beneficial to the utility. This last feature was suggested by Dr. Stutz at the July 20 meeting on AARs.

6. Customers on the rate will be required to provide hourly forecasts of their load.

7. The rate will pass the due discrimination test. I will explain this test in more detail after I have described the specific rate that I propose.

Q. WHAT AVAILABILITY REQUIREMENTS ARE YOU PROPOSING FOR THIS RATE?

A. I am proposing the same availability criteria that are currently included in the ELIIR, with but four exceptions.

- The ELIIR is currently limited to 275 MW. I would propose that this limitation be excluded for the current rate.
- The ELIIR rate specifies that customers on the rate must be able to provide at least 20 MW of interruption. I propose that the term “20 MW” be replaced by the term “significant blocks” to allow for greater flexibility.
- The ELIIR rate limits the rate to those customers taking service at 138 kV or above. I propose just requiring that customers take service at “transmission voltage” to make the rate more accessible.
- The customer must be reasonably expected to maintain a high monthly load factor, and has demonstrated this ability on a historic basis.

Q. WOULD THE CUSTOMER STILL BE REQUIRED TO PROVIDE CREDIBLE EVIDENCE THAT A SIGNIFICANT PORTION OF THEIR ANTICIPATED USAGE ON THE FP-DSM/DR RATE IS AT RISK?

A. Yes. However, as the FP-DSM/DR Rate is intended to supercede the ELIIR, the new tariff should specify that customers formerly approved by the Board for ELIIR would be considered eligible for this new below-the-line rate as well.

Q. WHAT RATE FORMAT ARE YOU PROPOSING?

A. I propose a rate with just four elements. The first is a demand charge based on a Contract Demand (CD). The contract demand could be changed only once every twelve months with 30 days written notice, with the following limited exceptions:

- By February 28 of each year, the CD could be lowered for the remainder of the calendar year for market reasons, but by no more than 10% of the existing CD.

- The CD could be reduced for a planned shutdown period; such shutdown periods cannot occur more than twice in any calendar year and must be specified three weeks in advance.

- The CD could be changed for a permanent alteration of production capacity or a DSM initiative.

- The CD could be suspended for force majeure reasons.

The Contract Demand charge is intended to make a contribution to NSPI's fixed generation and transmission costs.

The second element is an energy charge that would recover NSPI's average fuel costs (plus variable O&M and losses) if its entire system exhibited a 100% load factor, i.e. a perfectly flat load. This energy charge would apply to all energy (except buy-through energy) up to the Contract Demand.

The third element is an excess energy charge for all energy taken above the Contract Demand in any hour.

The fourth element is a cost based monthly customer charge.

(Exhibit N-61, pp.11-14)

[542] Dr. Rosenberg calculated that the FP-DSM/DR rate as proposed, at an assumed 85% load factor, would produce a combined rate of approximately $46.10 per

MWh.[183] In response to Dr. Stutz's IR-7, he recalculated his proposed rate using the same assumptions as NSPI and it was $48.85 per MWh.

[543] In Dr. Rosenberg's view, his proposed rate is cost based in the same sense as NSPI's witnesses maintained that ELIIR was cost based, when that rate was first being presented to the Board for approval. However, he does note that, if one were to adopt the view expressed by Dr. Stutz in the Generic Rate Design proceeding, then his proposed rate may not be considered cost based.[184]

[544] In response to an information request from NSPI, where the suggestion was made that domestic customers would be subsidizing SEB through increased rates, Dr. Rosenberg's response included the following statement:

> ...He would add, however, that the rate he is proposing can by no means be characterized a request to "subsidize SEB through increased domestic rates", the ultimate amount of which are in any event within the domain of the UARB.
>
> (Exhibit N-77, NSPI-SEB -IR-5)

[545] SEB responded to intervenor objections to the proposed FP-DSM/DR rate. In summary, SEB's position is that the FD-DSM/DR rate is cost based and SEB is not requesting a special discount or a rate driven solely by competitive pressures. It is not requesting a subsidy, but is simply requesting a rate that reflects the actual cost of service.[185]

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[183]Exhibit N-61, p.24

[184]Exhibit N-61, p. 23

[185]SEB Rebuttal Closing Submission, pp. 2 and 7

Intervenor Responses to the proposed FP-DSM/DR Rate

[546] Many of the intervenors filed evidence in response to the proposed FP-DSM/DR rate, or commented on the rate in their closing submissions. None of these intervenors supported the proposed rate. Many commented on the impact that the FD-DSM/DR would have on ATL rates.

[547] Mr. Drazen filed evidence in response to the proposed FP-DSM/DR rate on behalf of Avon. He summarizes his main points as follows:

> A. *First*, the increase to ELIIR customers is a higher percentage than to other customers because (1) ELIIR was set "below formula" in the previous case and, (2), ELIIR is by design more fuel intensive than other rates. *Second*, the rate proposed by Dr. Rosenberg's September evidence is not an accurate reflection of the cost of serving the ELIIR loads. Overall, the FP-DSM/DR proposal shifts a large amount of costs from ELIIR customers to the above-the-line (ATL) customers.
>
> (Exhibit N-100, p. 2)

[548] Ms. Brockway filed evidence for the Consumer Advocate responding to the proposed FP-DSM/DR rate. In her evidence, Ms. Brockway uses both the SEB response to Dr. Stutz IR-8 and NSPI's filed evidence[186] to conclude that the adoption of the FP-DSM/DR rate would transfer costs to the ATL customers and would result in a higher rate increase for these customers.

> ...The proposal of the below-the-line customers should be rejected unless they meet a heavy burden of demonstrating that such subsidies to their rates are not unjustly discriminatory, unfair, and otherwise violative of sound ratemaking criteria.
>
> (Exhibit N-99, p. 2, lines 19-22)

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[186]Exhibit N-88

[549] She concluded that the Board should not approve the FP-DSM/DR rate based on the state of the evidentiary record.[187]

[550] Dr. Stutz provided evidence on the proposed FP-DSM/DR rate. His recommendation is that the rate not be approved. The key points of his evidence are as follows:

> - The FP-DSM/DR does not provide either reasonable cost recovery or an appropriate credit for economic interruptibility.
> - For a non-cost based rate to be approved there needs to be evidence that the rate provides the minimum cost reduction required to retain load. Based on the information available, it is not possible to determine if the FD-DSM/DR rate satisfies this requirement.
>
> (Exhibit N-98, p. 2, lines 5-11)

[551] In their Closing Submissions, Avon, ECANS, MEUNSC and the Province all opposed the FP-DSM/DR rate. Many commented on what they saw as a transfer of costs from BTL customers to ATL customers.

[552] Avon states:

> [251] The Forest Products Rate is a non-starter. It is lower than the current rate when both fuel and non-fuel costs have risen. It is devoid of any reasonable justification, any reasonable connection to the cost of serving SEB and has no prospect for public acceptability by the above the line customers who would be required to provide a massive subsidy to Stora Enso and Bowater.
>
> (Avon, Redacted Closing Submission, p. 53)

[553] ECANS' position is stated as:

> ... More pointedly, if SEB are granted special status by having access to rates at less than cost, then any shortfall will be assigned to Above-the-Line customers. In NSPI's N-88, a $33 million transfer of costs would result in a 3%+ increase in the ABL classes. This is not acceptable.

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[187] Exhibit N-99, p. 9

> If SEB need lower electricity rates to remain competitive in their markets, they should look to Government and the taxpayer to address the challenge. Economic subsidization is not within the Board's mandate.
>
> (ECANS, Redacted Closing Submission, pp. 14-15)

[554] In his Closing Submission, the Consumer Advocate takes the position that it will not address the FP-DSM/DR rate on the basis that the design of a new rate part way through the proceeding is "rate design on the fly", and is not the appropriate regulatory approach.[188]

ELIIR Modifications/Replacement

[555] Dr. Rosenberg's evidence recommends a number of changes to the NSPI computations of the ELIIR rate. The changes were proposed in the eventuality that the FP-DSM/DR rate is not accepted or not accepted prior to January 1, 2006.[189] Dr. Rosenberg states that his computed reduction still results in rates that are far too high to characterize as competitive and these reductions do not lessen the need for the FP-DSM/DR rate.[190]

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[188] Consumer Advocate, Redacted Closing Submission, p. 15, para. 59

[189] Exhibit N-91, p. 23, lines 18-22

[190] Exhibit N-91, p. 31, lines 13-19

Dr. Stutz's ELIIR Adjustment

[556] As previously mentioned, Dr. Stutz recommends that a successor to the ELIIR should be developed. In his evidence, Dr. Stutz provided some comments on the type of rate that should replace ELIIR:

> ... ELIIR and FP/DSM-DR both provide a credit in exchange for interruptibility. However, they do not specify the credit directly. Rather, they build it in through the design of their charges. Instead, one should begin with LIR, the cost-based rate on which SEB would take service if it were not interruptible and add an explicit economic interruptibility credit to the existing rider for supply interruptibility. A rate designed this way would be preferable to ELIIR or FP/DSM-DR because the value of interruptibility would be stated clearly and directly. Development of this rate should include a thorough review of the value of supply and economic interruptibility. If LIR with the appropriate credits for interruptibility does not meet SEB's business needs, SEB could ask the Board to add a separate rider for load retention.
>
> (Exhibit N-98, p. 9, lines 6-16)

[557] Dr. Stutz 's position, as outlined in his opening statement, is that the time has come to set a firm schedule to replace ELIIR with a new rate.[191] He added that this issue should be settled by the end of 2006. Dr. Stutz's opening statement provided further detail on what adjustments are required to the NSPI's filed ELIIR rate and how the rate may be computed from the Large Industrial Interruptible Rider (LIIR) rate:

> A key feature which distinguishes ELIIR from the Large Industrial Interruptible Rider (LIIR) is economic interruptibility. To be fair to those served on ELIIR and to other ratepayers, the cost of service on ELIIR needs to be roughly equal to the cost of service on LIIR less the likely cost of buy-through. ...Thus, based on the assumptions in NSPI's filing, an adjustment of about $6.30 to NSPI's proposed ELIIR energy charge is needed. This adjustment simply allows the savings due to economic interruptions to pass through to the customers on ELIIR who made the savings possible.
>
> (Exhibit N-244, p. 3)

[191]Exhibit N-244, p. 2

[558] During cross-examination by Al Dominie of MEUNSC, Dr. Stutz explained that he recommends a two step process for dealing with ELIIR: first, to put an appropriate ELIIR charge in place for 2006; and the second, is to replace ELIIR with a new rate. The first step is what needs to be accomplished as part of this proceeding.[192]

[559] Dr. Stutz filed Exhibit N-241, which provided a computation and proposed ELIIR rate for 2006. The resulting average adjusted ELIIR rate is $54.89/MWh.

[560] During cross-examination by Mr. Grant, Dr. Stutz stated that the savings to SEB under his proposed ELIIR rate for 2006 using a rate of $54.89/MWh versus the proposed NSPI ELIIR and 2P-RTP rates would be approximately $13 million.[193] Dr. Stutz provided details of the computation (along with some comments on the computation) in response to Undertaking U-88. He did not agree with the characterization by Mr. Grant that this would transfer $13 million to ATL customers. It is his view, that "we're simply setting the rate correctly".[194]

[561] Dr. Stutz was also cross-examined on the impact of his proposed ELIIR adjustments on other ratepayers. The following exchange occurred between Dr. Stutz and Mr. Grant:

> Q: Thank you. Dr. Stutz, have you calculated whether rate payers who are not on the ELIIR rate would be better off having Stora Enso Bowater under the rate as you propose to modify it than not at all?
>
> A: I haven't calculated it, but I think it's clear that they're better off with them than without them. And the reason I say that is that my rate charges them based on the LIR, which is an above the line, cost based rate, and the difference is a credit which, by design,

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[192]Transcript, December 2, 2005, p. 3546

[193] Transcript, December 2, 2005, p. 3530

[194] Transcript, December 2, 2005, p. 3547

their economic interruption finances. So unless it's undesirable to have customers on the LIR rate, it follows that it's economically desirable to have them on my version of ELIIR.

Q: It's clear, though, is it not, that for the other rate payers it's preferable to have Stora Enso Bowater on the existing ELIIR rather than on the EIIIR as you've proposed?
A: Absolutely.

(Transcript, December 2, 2005, p. 3534)

[562] Dr. Rosenberg addressed Dr. Stutz's proposal in his opening statement:

... I acknowledge that Dr. Stutz's top-down approach to a replacement to the ELIIR formula could be workable and may engender less controversy than the bottom up approach that I had proposed in my FP testimony. In fact, in my Rebuttal testimony I showed how such a top-down approach could be used to fashion the FP DSM/DR rate by subtracting the value of interruptibility from a suitably adjusted Large Industrial Rate, and how the result of such a top-down approach compared to the rate that I had initially derived. I use the words "suitably adjusted" because it is necessary to first distinguish between the physical cost of serving the FP customers, as opposed to serving LIR customers, before we can even begin to account for the value of interruptibility.

(Exhibit N-235, p. 2)

[563] Dr. Rosenberg went on to state that:

While I have adopted Dr. Stutz's recommended value-driven methodology (adjusted as I have recommended), to derive the overall dollar figure for the rate, I maintain my recommendations for the form of the replacement for ELIIR i.e. I continue to recommend the FP rate form.

(Exhibit N-235, p. 2)

[564] In general, other intervenors took the same position on Dr. Stutz's proposed rate as they did on Dr. Rosenberg's FD-DSM/DR rate. For example, ECANS states that neither proposal is acceptable[195], the Consumer Advocate states there should be no

[195] ECANS, Redacted Closing Submission, p. 14

adjustment to the ELIIR rate, or alternatively, less than that proposed by Dr. Stutz[196], and Avon submits that Dr. Stutz's adjustment should not be made for 2006[197].

10.5.3 Findings

[565] NSPI is proposing that the new ELIIR monthly charge be $24,100 and the energy rate be $60.80 per MWh (at 85% LF) effective January 1, 2006 to December 31, 2006. This results in an approximate combined ELIIR rate of $61.19 per MWh. NSPI states that the main reason for the increase in the proposed ELIIR rate is substantially higher fuel costs in 2006. It further submits that the proposed rate is based on the formula approved by the Board and that any changes to the formula should be reviewed in a separate hearing in 2006 for a rate to be effective in 2007.

[566] SEB has taken the position that the proposed 2006 ELIIR rate, calculated based on the current formula, is not workable and does not achieve the results it was intended to achieve. SEB has proposed the new FP-DSM/DR rate, which it claims is based on the actual cost of service for this customer class.

[567] Dr. Stutz is of the view that the ELIIR should be replaced with a new rate to directly reflect credits for economic interruption. He is suggesting that a reasonable solution would be to start with LIIR and create a formula to apply appropriate credits. He is also of the view that a separate hearing should be held in 2006 and a new rate be approved no

[196] Consumer Advocate, Redacted Closing Submission, p. 2

[197] Avon, Redacted Closing Submission, p. 55

later than the end of 2006. In the meantime, he recommends a temporary ELIIR rate of $54.89/MWh for 2006.

[568] All other intervenors have objected to the suggestions by SEB and Dr. Stutz because they would result in a shift in the revenue requirement from the BTL customers to the ATL customers without following the normal due diligence process for approving new rates.

[569] The Board has carefully considered the evidence and submissions on this issue. The Board concludes that the FP-DSM/DR rate proposed by SEB is not cost based and would create an undue burden on ATL customers. Accordingly, the Board is not prepared to approve the FP-DSM/DR rate.

[570] It is clear to the Board that ELIIR is not working as it was originally intended to by both NSPI and SEB. For whatever reason, it does not appear to provide reasonable compensation for economic interruptibility. Therefore, the Board will hold a separate hearing in 2006 to consider a replacement for ELIIR, which will become effective January 1, 2007. The Board directs NSPI to file an application for a new rate to replace ELIIR, after consultation with its customers, no later than June 30, 2006.

[571] For the current year, the Board has been presented with two cost based approaches for setting the energy charge in ELIIR. NSPI supports the use of the formula in the existing tariff. The Board understands that Dr. Stutz recommends beginning with the LIR - that is the Large Industrial Rate at an 85% load factor, less the transformer ownership credit and the value of the interruptible supply credit of $3.43 per month per kVa. Dr. Stutz

then subtracts the value of economic interruptibility, which he calculated at $8.43 per MWh. Each of these approaches has strengths and limitations. The ELIIR formula has been approved but, for 2006, does not appear to provide reasonable compensation for economic interruptibility. Dr. Stutz's approach is conceptually correct, but does not provide a fully developed alternative for ELIIR. To give weight to each approach, the Board directs NSPI to set the ELIIR energy charge by averaging the results produced by the two approaches.

[572] In setting the ELIIR energy charge, the Board directs NSPI to use the fuel budget, and all other items having an impact on ELIIR, as approved in this decision. The Board also directs NSPI to iterate its rate calculations, to ensure consistency between the LIR charges used to set ELIIR and those to be paid by customers on the LIR.

[573] As previously indicated, the Board has directed NSPI to develop and file a replacement for ELIIR. Both NSPI and SEB have agreed that Dr. Stutz's approach to the development of such a replacement—beginning with a firm rate and then specifying credits for interruptibility—has merit. While the Board concurs, it would be prepared to consider other viable options which may be developed.

[574] NSPI proposed to add Special Condition 5 to the ELIIR tariff, the purpose of which is to require customers to file an hourly demand forecast on a day-ahead basis. Because the current version of ELIIR is about to be replaced, the Board will not approve any changes in the present tariff language. Upon filing, the Board will approve, effective January 1, 2006, the interim ELIIR rate calculated in accordance with this decision.

11.0 OTHER ISSUES

11.1 Load Forecast

[575] The details of NSPI's load forecast for the test year are provided in the 2006 Load Forecast Report appended to the Company's application as Exhibit N-2, Appendix F. Further information in support of the load forecast is contained in Exhibit N-1, pp. 162 to 179. In-province electric energy sales are forecast to grow by 1.2% in the 2006 test year despite an average annual growth rate of 2.6% over the past five years. NSPI states that the reduced growth rate for the test year is reflective of the impact of existing DSM initiatives. In comparison to the projected figures for 2005, residential sector sales in 2006 are expected to rise by 1.1%, commercial sector sales by 2.1% and industrial sector sales by 0.5%.[198]

[576] Peak demand for the winter of 2005/2006 is forecast to be 2,172 MW, a slight increase from the figure of 2,143 MW in the previous winter. The projected peak demand assumes a 60 MW reduction due to economic interruption at the time of system peak.[199]

[577] In its load forecast for the 2006 test year, NSPI has accounted for the impact of ongoing DSM initiatives which, NSPI states, will reduce in-province electric energy sales, as well as reduce peak demand by 13 MW.

[578] In its response to the Province IR-55, NSPI estimated that existing DSM initiatives will result in a reduction of 65 GWh for the 2006 test year. This reduction was

[198] NSPI Application, Exhibit N-1, p. 162

[199] NSPI Application, Exhibit N-1, p. 162

done manually by reducing its residential forecast by 1% (i.e., 42.7 GWh) and its commercial forecast by 0.5% (i.e., 16.7 GWh). NSPI's load forecast is typically calculated using an econometric model as defined in the Company's Load Forecast Report.[200] As it reiterated during the hearing, NSPI asserts that DSM's impact on the 2006 load forecast is the result of existing educational and awareness programs carried out by government and other agencies. NSPI states that the Company's own DSM efforts will only commence to impact its load forecast in the 2007 test year.[201]

[579] In Direct Evidence and oral testimony, Dr. Stutz expressed concern that NSPI's revenue forecast for 2006 may already be too low and that the Board should not approve NSPI's DSM-related adjustment to its load forecast. He stated:

> ... NSPI's statistically based residential and commercial forecasting models will reflect all ongoing DSM. An adjustment is only needed to account for the impact of new, incremental DSM activities. NSPI intends to develop new DSM initiatives. However, the specific programs are still unspecified. The 1.0 and 0.5 percent adjustments are based on assumptions, not estimates based on specific incremental DSM initiatives.
>
> Once specific programs are developed, time will be required to inform potential participants about the programs, for them to decide if they wish to participate, and for the participants to take the step promoted by the programs. There is almost no allowance for "start up" in NSPI's DSM adjustment.
>
> ...
>
> The impact of incremental DSM is more likely to follow and S-shaped "logistic curve," with very low impacts in the early years as knowledge of the program spreads, rapid increase in the middle years as the program takes hold, and decreasing growth in the later years as market saturation occurs.
>
> ...
>
> I recommend making no DSM adjustment at all. This recommendation reflects the fact that the 1.0 and 0.5 percent impacts are an assumption rather than an estimate of the impact of

[200] Exhibit N-2, Appendix F

[201] Province IR-55

> a specific incremental DSM program, the likelihood that any effect of incremental DSM will phase in slowly at first, and the concern that NSPI's underlying forecast of sales for 2006 may already be too low.
>
> (Stutz, Pre-filed Evidence, Exhibit N-81, pp. 16-17)

[580] In cross-examination by Mr. Connors, Dr. Stutz acknowledged that Exhibit N-229 may provide some evidence of incremental activity in support of NSPI's adjustment to its load forecast.[202] This exhibit outlined, according to Alan Richardson, NSPI's General Manager, Customer Service, better than anticipated results of the CFL program. In the end, however, Dr. Stutz believed there should be a detailed analysis to support the reduced load forecast and that the survey results (i.e., Exhibit N-229) are not normally the way utilities prove adjustments to their forecasts.[203]

[581] During the 2005 rate case, Dr. Stutz also expressed concerns that NSPI's sales forecast was too low. In its decision, the Board concurred with his view:

> [296] The Board shares Dr. Stutz's view with respect to the load forecasting issue. The Board accepts his recommendation and directs NSPI to initiate meetings with Dr. Stutz and Board staff to attempt to resolve these concerns.
>
> [297] The Board also directs that a report on the progress of improvements to NSPI's load forecasting methodology be filed by December 1, 2005.
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> (Board Decision, March 31, 2005)

[582] By letter dated November 29, 2005, NSPI requested that the Board postpone the requirement for the filing of this report. In a letter dated December 14, 2005, the Board

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[202]Transcript, December 2, 2005, p. 3576

[203]Transcript, December 2, 2005, pp. 3572 and 3576

agreed to postpone the filing of the report pending the review of this issue by NSPI and Dr. Stutz.

[583] Several intervenors also opposed NSPI's proposed DSM-related adjustment to the load forecast. Avon adopts Dr. Stutz's concerns with respect to the adjustment, particularly in light of his remarks that the load forecast may already be too low. SEB submitted that NSPI did not provide adequate support for the adjustment, including the Company's responses to NSDOE IR-55, SEB IR-131 and Exhibit N-229.

[584] Testifying on behalf of the Consumer Advocate, Ms. Brockway expressed reservations about NSPI's estimate of the impact of DSM on load projections. She stated that the Company had not incorporated the results of various studies and technical literature outlining the impacts that can be expected from different types of DSM activities.[204] Ms. Brockway was specifically asked by the Board about NSPI's estimated impact of DSM efforts with respect to the 2006 test year:

> Q. (Deveau) And I'd refer you quickly, if I could, to Exhibit N-229. And that was an exhibit presented yesterday by Mr. Richardson. I believe you were here when he probably spoke about that.
> A. Yes.
>
> Q. And that's -- that was an exhibit that he presented when -- based on his evidence that NSPI was actually experiencing penetration rates quicker than they had anticipated. And this is based on a survey and the extrapolations made based on the customers and the number of bulbs that had been installed. Do you have any comments to make with respect to this type of research that has been tendered?
> A. Well, actually, there was -- yes, I do. Thank you, Mr. Commissioner, because I would align myself with those comments that were either made or suggested by some that it's very common in survey research for respondents to give the questioner the answer that they think the question wants, particularly when you have raised cultural awareness of the importance of the right answer being, "Yes, I've got more CFLs." And ---

[204] Brockway Opening Statement, Exhibit N-242

Q. People are embarrassed to say they haven't.
A. Yes. Now, in some cases their memory has been adjusted to meet their expectations of themselves, and it's not a conscious lie. I'm not saying that. But the survey -- this kind of a survey research is well understood to be unreliable as -- certainly as the sole basis for estimating how much behaviour has changed. The other thing that I noted about this is that I would expect that the estimates of how many hours the bulbs are on is -- at least with respect to the five hours, that that's an over statement, that in very few households would an average of two and a half bulbs be on for five hours a day all year long. They might be in the depth of winter, but that's not all year long. So I think some of the wrong assumptions are being drawn from this, that the estimates are over stated.

(Transcript, December 2, 2005, pp. 3505-3506)

11.1.1 Findings

[585] Based on its review of the evidence, the Board is not persuaded that NSPI's manual adjustment to its load forecast should be approved. While the survey results shown in Exhibit N-229 are encouraging with respect to the positive impact of programs like the CFL initiative, the Board concurs with Dr. Stutz that this is not the appropriate way for a regulated utility to prove a reduction of its load forecast and, further, does not justify the manual adjustment made by NSPI.

[586] As noted above, NSPI's load forecast is typically calculated using an econometric model. While the Board is mindful that DSM is a relatively new initiative, it considers that the impact of some DSM programs is already embedded, at least in part, in the variables comprising the econometric model. Moreover, the Board notes Dr. Stutz's concern that NSPI's underlying load forecast may already be too low for the 2006 test year. In such circumstances, the Board is reluctant to allow a reduction which would result in an even lower load projection.

[587] Based on the evidence at the hearing, the Board concludes that denying the DSM-related load forecast reduction would increase variable costs for NSPI by about $5.1 million, while corresponding revenues from electricity sales would increase by approximately $6.3 million based on NSPI's proposed rate increase.[205] While these responses to the SEB IRs translate into a net reduction of $1.2 million in the revenue requirement, Avon asserts that the difference could be as high as $2.0 million.[206] It is the Board's understanding that because of the potential net savings of between $1.2 million - $2.0 million, the proposed rate increase sought by NSPI will go down. For the purpose of its decision, the Board's estimate of the impact is $1.6 million. The Company is directed to address the impact of the Board's denial of the DSM-related load adjustment in its Compliance Filing.

[588] As noted above, by letter dated December 14, 2005, the Board agreed to postpone the filing of a report by NSPI with respect to its load forecasting methodology, a report which was ordered by the Board in the 2005 rate decision. In its letter requesting the postponement, NSPI indicated that the delay would facilitate discussion of the load forecasting issues with Dr. Stutz in 2006. The Board directs that NSPI file its report on the progress of improvements to its load forecasting methodology by December 29, 2006. This extension of the filing deadline should allow NSPI to incorporate its response to the DSM-related load reduction issues noted by Dr. Stutz.

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[205] SEB IR-227, SEB IR-131

[206] Avon, Redacted Closing Submission, p. 46

11.2 Unmetered Rates

[589] HRM and the Union of Nova Scotia Municipalities ("UNSM") contend that an inordinate level of costs is being assigned to the Unmetered Class, which is primarily comprised of municipalities. As noted by Warden Richard Cotton, President of the UNSM, who spoke during the evening session, the unmetered rate is of great significance to municipalities because it represents almost 50% of the total of municipal electric bills.[207]

[590] In order to assign costs to its customer base in the Unmetered Class, NSPI uses a designated number of accounts as a surrogate for customers within the Class, referred to as the "weighting factor". For the C-3 Class, a weighting factor of 5.0 is applied to the number of accounts. HRM and the UNSM assert that this formula is not reflective of the costs actually being incurred for the provision of service to the Unmetered Class. In their view, the number of accounts do not bear the same relationship to costs as the number of customers do. They submit that municipalities use services such as billing or the call centre far less than other customers.

[591] HRM retained Robert Greneman, of Stone & Webster Management Consultants, Inc., to review this issue. In his pre-filed evidence, Mr. Greneman submits that the weighting factor of 5.0 for the Unmetered Class bears no relation to cost causation. He states that billing, customer service and call centre expenses for unmetered accounts are no greater than for residential accounts and, therefore, the weighting factor should not exceed 1.0. He concludes:

[207]UNSM Presentation, November 23, 2005

> NSPI should undertake a more detailed analysis of the activities that are included in factor C-3. I recommend that until such analysis is completed, this Board direct NSPI to set the weighting to the Unmetered class in factor C-3 from 5.0 to 1.0, beginning in this proceeding.
>
> (Greneman, Pre-filed Evidence, Exhibit N-85, p. 16)

[592] The UNSM estimates that reducing the weighting factor from 5.0 to 1.0 would reduce municipal electric bills by over $1 million across the province.[208]

[593] HRM states that a street lighting study was last conducted by NSPI in 1975, which forms the basis for the present allocation in the Cost of Service Study ("COSS"). HRM asks that a new streetlight study be undertaken to ascertain the number and type of fixtures, their age and actual maintenance data, broken out by municipality, and that the study include a review of current maintenance practices across Canada to establish a Best Practices Lighting Maintenance Standard. The UNSM adds that such a study should include data respecting the energy consumption of streetlights, to assist it in developing energy reducing strategies. Further, HRM asks that the study gather data to determine the number and origin of calls to NSPI billing staff respecting unmetered services.[209]

[594] Mr. Greneman also states in his pre-filed evidence that NSPI should identify the portion of rate base allocated for vehicles and plant associated with the meter reading function and that the Company should remove the related interest, return, taxes and depreciation from its allocation to the Unmetered Class.[210] While HRM acknowledges that

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[208]UNSM Presentation, November 23, 2005

[209]HRM, Redacted Closing Submission, p. 1

[210]Greneman, Pre-filed Evidence, Exhibit N-85, pp. 16-17

any direct costs related to meter reading were removed from the Unmetered Rate as a result of the last rate hearing, it asks that the same adjustment be made with respect to indirect meter reading costs.[211]

[595] HRM also asserts that NSPI's COSS shows that almost $26 million of rate base associated with lighting fixtures was assigned to the Unmetered Class, attracting approximately $5.7 million of costs for depreciation expense, taxes, interest and return. In HRM's view, this allocation to rate base is a primary reason the Unmetered Class must pay $0.22/KWh, well above other classes.[212] Based on NSPI's response to Undertaking U-31, HRM submits that the Unmetered Class has not received any credit from NSPI for the new lighting installations contributed by developers and property owners over the past ten years. HRM believes that if such contributions were properly credited to the Unmetered Class, the rate base assigned to this class would decrease by more than 50%. It estimates that such costs comprise approximately $5.7 million or 22.5% of the proposed revenue requirement for the Unmetered Class.[213] HRM asks the Board to reduce the rate base directly assigned to the Unmetered Class to a level of 40% of that currently stated, until a proper assessment of contributions is made by NSPI.

[596] In its Closing Submission, NSPI indicated the following with respect to HRM's request for a review of the C-3 Unmetered Class allocator shown in the COSS:

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[211]HRM, Redacted Closing Submission, p. 8

[212]HRM, Redacted Closing Submission, p. 8

[213]HRM, Redacted Closing Submission, p. 10

> NSPI agrees that the study used to develop the C-3 weighting factor for the unmetered class should be updated if the factor is to be changed. This would require the acquisition and analysis of customer-service-related activity relating to unmetered services over some representative period of time. NSPI plans to gather this information by April 1st.
>
> NSPI also agrees that the study of direct costs for street lights, including installation and maintenance costs, requires updating. NSPI plans to complete this work by July 1st.
>
> (NSPI, Redacted Closing Argument, p. 87)

11.2.1 Findings

[597] The Board is satisfied that a study should be conducted to determine whether the present weighting factor of 5.0 is still appropriate as the C-3 Unmetered Class allocator. Further, it determines that NSPI's suggested time line is appropriate in the circumstances.

[598] The Board directs that a cost of service study be conducted by NSPI with respect to the Unmetered Class. The study shall include a review of the appropriateness of the current weighting factor and a review of the rate base, including assets, assigned to the Unmetered Class. The study should indicate a breakdown of costs and rate base by municipality.

[599] The Board directs that the current weighting factor of 5.0 should remain in effect for the 2006 test year.

[600] The cost of service study results shall be filed with the Board by July 31, 2006.

11.3 Miscellaneous Charges

[601] NSPI has requested increases to its miscellaneous charges, as outlined in Exhibit N-2, Appendix I, along with proposed language changes to certain of its regulations

as outlined in Exhibit N-2, Appendix J. In keeping with the Board's direction in the 2005 rate decision, NSPI is limiting the proposed increase to the average rate increase for ATL customers.

[602] The Company submits that the proposed increase to miscellaneous charges brings them closer to recovering the actual costs of providing the service. In the four instances where incorporating the average ATL rate increase would have resulted in charges which exceeded the cost to deliver the service, the proposed rate increase was capped to reflect the actual cost.[214]

[603] As noted in the 2005 rate decision, it is not appropriate for the Company to charge a profit margin on miscellaneous charges. NSPI has removed any such mark-up in the present application.

[604] Ms. Brockway testified that the Board should deny most of the proposed increases to miscellaneous charges, particularly since those charges had already been increased considerably in 2005. In her view, these charges have a significant impact upon low income customers, expressing particular concern about the following charges:

- Regulation 7.1(a), Connection/Reconnection during normal working hours
- Regulation 7.1(b & c), Connection/Reconnection after normal working hours
- Regulation 7.1(e), Collection charge (Doorknob charge)
- Regulation 7.1(e), Collection charge (Registered Letter)
- Regulation 7.1(g), Returned Cheque Charge

[605] In her Direct Evidence, Ms. Brockway explained the basis for her concern:

> Customers with fixed incomes, seasonal incomes, poverty-level wages, and the like, are disproportionately likely to fall into arrears, and be subject to collection practices requiring

[214]NSPI Application, Exhibit N-1, p. 198

collection actions (doorknob notices, registered letters), and to disconnection, requiring reconnection. Indeed, for working poor families, reconnection will usually have to take place after hours, or someone will have to take off work at great cost in order to be present during the reconnection. Also, with respect to charges intended to prevent "leaning" on the system, they are not likely to have that salutary effect in the case of low-income customers with payment difficulties, as these customers will not become better able to pay their bills merely by making them higher.

...

I recommend that the charges for reconnections, collections and returned cheque charges not be increased at this time, but remain as set in the March 2005 order. I recommend that the difference in revenues be spread equally to all classes. The impact will be de minimis on customers not paying these charges, but will be most welcome for customers with limited incomes who are already struggling to keep up with rising energy costs.

(Brockway, Pre-filed Evidence, Exhibit N-87, pp. 15-16)

[606] The Consumer Advocate submits that more rigorous standards of "cost recovery" are being applied to low income customers than to other classes of ratepayers. In his view, the pursuit of "cost recovery" as against low income customers should be carried out with the same exactitude as that adopted with respect to the recovery of costs from other ratepayer classes. Describing this phenomenon as a type of discrimination, the Consumer Advocate argued:

68. No party would dispute the impact of such charges is particularly onerous for those on low incomes and who are the most susceptible of incurring the charges. The only argument in favour of the requested increases is that they are needed to recover the costs involved and to dissuade customers from defaulting on payments.

69. Yet there can be no doubt that any similar analysis of cost recovery for other rate classifications, particularly the AAA rates, would raise questions as to the exact dollar cost recovery of the applicable rate. The reality is that precise and undisputed cost recovery is not possible and often is explicitly recognized or even intended. The justification is that there must be practicality to rate structures. That justification often finds its expression in the concept of due discrimination. Whatever it is called, the reality is that many, if not all, rate classifications have some degree of uncertainty whether there is perfect cost recovery. Often the inquiry is dropped because of the size of the ratepayer and their importance to the maintenance of the system.

70. Yet when it comes to recovering the full amount of doorknob notices or returned cheques, the pencils are sharpened to ensure the costs are recovered.

...

72. ... While it is not the function of the Board to use rates as an instrument of social policy, there is no need to be any more precise in recovering default costs from consumers than recovering the costs of service from the various rate classifications.

(CA, Redacted Closing Submission, pp. 17-18)

[607] In its Closing Submission, the Affordable Energy Coalition ("AEC") reiterated Ms. Brockway's view that there should be no increase to miscellaneous charges, stating that such charges have a "disproportionate impact" on low income customers.[215]

[608] The AEC urges the Board to adopt Ms. Brockway's suggestion to spread the shortfall in revenues from these charges equally across all classes, stating that this approach will satisfy the Board's obligation to ensure that charges are not unduly discriminatory, as required by **s. 67(1)** of the **Public Utilities Act**.[216] In her evidence, Ms. Brockway testified that spreading the charges in this fashion would have a *de minimis* impact on customers.

[609] The NDP Caucus submits that individual customers should not be charged for such services and that they be absorbed into general operating costs.[217]

11.3.1 Findings

[610] Having reviewed this matter, the Board considers it appropriate to proceed in a manner consistent with the approach it adopted in last year's rate case. Accordingly, the

[215]AEC, Redacted Closing Submission, pp. 18-19

[216]AEC, Redacted Closing Submission, p. 19

[217]NDP Caucus, Redacted Closing Submission, p. 12

Board approves the proposed increases to miscellaneous charges sought by NSPI. As noted above, in the event such increases result in a charge which exceeds the cost of delivering the service, the charge must be capped at the actual cost.

11.4 Low Income Consumers

[611] The AEC submits that the Board has a statutory obligation to protect the public interest by ensuring that the services provided by NSPI are affordable for its customers, including low income customers. Referring to the evidence of Mel Boutilier, Executive Director of the Parker Street Food and Furniture Bank, and of Joan Jessome, President of the NSGEU, the AEC noted that the impact of electricity rates upon low income customers manifests itself in various ways, including homelessness, evictions, unsafe heating practices, health problems related to inadequate heating and refrigeration, hunger, and other social and housing related problems.[218]

[612] The AEC noted that current programs, although helpful, are not adequate to address the needs of low income customers. It described a number of these programs, including a program providing financial assistance which is administered by the Department of Community Services, relief provided by charities and churches, the Keep the Heat Program offered by the provincial government which provides heating rebates, and the

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[218] AEC Redacted Closing Submission, p. 5

Good Neighbour Program, which receives approximately $307,000 through donations from NSPI, its customers and employees.[219]

[613] While recognizing that DSM initiatives are important for low income residential customers, the AEC adds:

> ... Energy efficiency measures alone will not result in electrical services which are affordable to all: low income programs must include rate assistance, crisis intervention and improved arrears policy and management.
>
> (AEC, Redacted Closing Submission, p. 3)

[614] The AEC cites **ss. 44** and **67** of the **Public Utilities Act** in support of its view that the Board should develop programs which ensure electrical service is affordable and accessible to all consumers:

> 45. Here, in order for the Board to make a "just" order under s. 44, one that avoids a rate structure which created effective barriers to equal access for the poor, it is appropriate - and *Charter* compliant - for the Board to order programs to accommodate the disadvantage experienced by low-income people.
>
> 46. In resolving any ambiguities concerning the scope of the Board's power to decide on the implementation of a Rate Assistance Program, and the correct interpretation of section 67(1), the Board must avoid interpretations which would have the effect of excluding consumers from essential services based on protected grounds, including their socio-economic status.
>
> (AEC, Redacted Closing Submission, pp. 15-16)

[615] Thus, AEC asserts that the Board must apply the jurisdiction conferred upon it by its enabling legislation, in a manner consistent with the equality provisions of the

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[219] Undertaking U-13

Canadian Charter of Rights and Freedoms, in order to ensure non-discriminatory access for low income customers to electricity services.

[616] In its Closing Submission, the Consumer Advocate stated:

> 73. NSPI made reference several times to giving consideration for low income consumers. They are to be commended for identifying that as an objective. Yet apart from the Good Neighbour program, for which their contribution is to be commended, there was a lack of any specific action, programs or steps relating specifically to low income consumers. All NSPI could say was that they would try to ensure that their existing services would be available to low income consumers.
>
> 74. We ask that the Board in its decision emphasize the importance of developing concrete and specific steps directed to the low income consumer.
>
> (CA, Redacted Closing Submission, para. 73-74)

[617] The NDP Caucus also asked the Board to revisit a proposal made by the AEC during the prior rate hearing to create a system of supports for low income customers.[220]

[618] In its 2005 rate decision, the Board determined that it does not have the statutory authority to approve a rate assistance program and that the issue is a "social and public policy question which falls within the purview of the Legislature rather than the Board."[221]

11.4.1 Findings

[619] Following the issuance of its 2005 rate decision, Dalhousie Legal Aid appealed the Board's decision. The appeal is set to be heard by the Nova Scotia Court of

[220] NDP Caucus, Redacted Closing Submission, p. 12

[221] Board 2005 Rate Decision, para. 256

Appeal. In the circumstances, the Board considers it prudent to await the disposition of the appeal before it undertakes any further review of the issues raised by the AEC.

11.5 Pole Attachment Fees

[620] In its pre-filed evidence, RuSh Communications Ltd. ("RuSh") expressed concern that some of the additional costs projected in OM&G for storm response, vegetation management and storm proofing are already being recovered in the rates charged to telecommunications clients such as RuSh. It asserts that costs for storm response, vegetation management and storm proofing are already included in NSPI's pole attachment rate of $14.15 and its incremental "make-ready" charges for vegetation management and general maintenance on structures accessed by tenants like RuSh to upgrade their equipment.[222]

[621] NSPI denies the assertions made by RuSh. It notes that the revenues received from pole attachment fees and "make-ready" charges are separately accounted for in the revenue requirement for the 2006 test year. It further notes that the $14.15 pole attachment fee only covers capital recovery, routine general maintenance and vegetation management, while additional construction or plant upgrade costs are recovered in "make-ready" charges.[223]

[222] RuSh Communications, Pre-filed Evidence, Exhibit N-86

[223] NSPI, Rebuttal Evidence, Exhibit N-153, pp. 108-109

11.5.1 Findings

[622] The Board concurs with NSPI's position on this issue. The setting of the pole attachment fee, as well as the scope of costs recovered under that rate and under "make-ready" charges, were canvassed by the Board in its Decision on such issues dated January 24, 2002. The Board is satisfied that NSPI's allocation of costs is in accord with that Decision and that the Company's proposed rate increase does not result in a duplication of the revenue earned from pole attachment fees and "make-ready" charges.

11.6 Renewable and Environmentally Sustainable Energy

[623] Some of the intervenors asked the Board to consider environmental issues in assessing NSPI's application for a rate increase.

[624] In its Closing Submission, the Ecology Action Centre submitted that energy issues are "inherently environmental issues". In its view, a rate increase is only justified if the resulting increase in revenues is directed towards making energy production, distribution, and consumption environmentally sustainable. According to the EAC:

> ... The EAC maintains that energy security for Nova Scotia residents would be best provided by including a combination of more aggressive and practical Demand Side Management (DSM) programs and greater encouragement of the development of clean and sustainable energy sources for Nova Scotia.
>
> The EAC believes that NSPI must focus on a sustainable, long term vision for electrical energy production and distribution in Nova Scotia. The EAC asserts that, as it is now designed, NSPI's current rate application simply prolongs Nova Scotia's reliance on coal and other fossil fuels to produce electricity.
>
> (EAC, Redacted Closing Submission, p. 1)

[625] In addition to submissions respecting DSM, the EAC made a number of recommendations related specifically to renewable and environmentally sustainable energy, including:

> 2) That NSPI develop a more ambitious strategy to reduce green house gases (GHGs) and pollution through renewable energy generation programs, internal NSPI DSM initiatives, and more extensive DSM services for customers in all rate classes.
>
> ...
>
> 3) That all coal and natural gas plants in Nova Scotia be retrofitted to reduce air pollution and waste energy. This includes the fitting of scrubbers at all thermal generating stations that remain in service, the deactivation of sites that cannot be fitted with pollution controls in a cost effective manner, and the installation of systems to recover waste heat.
>
> ...
>
> 4) That NSPI amend its Renewable Portfolio Standard (RPS) and increase its commitment to green energy production by increasing the minimum amount of total energy production to come from new renewable sources from five percent by the year 2010 to ten percent by 2010[sic] and twenty percent by 2015.
>
> ...
>
> 5) That the UARB support the use of standard offer contracts to encourage the development of local renewable energy production initiatives, and that the conditions and price paid be determined by the UARB.
>
> ...
>
> 6) That the UARB consider in its rate case ruling the introduction of a systems benefit charge to facilitate funding of DSM and renewable energy initiatives administered by an independent agency.
>
> ...
>
> 8) That an independent study be conducted to investigate alternative rate designs for the purpose of developing a rate structure for Nova Scotia which most appropriately furthers economic and environmental sustainability. The EAC is interested in the idea of implementing an inverted block rate in all classes, coupled with strong DSM initiatives.
>
> (EAC, Redacted Closing Submission, pp. 2-6)

[626] In its Closing Submission, the NDP Caucus echoed the EAC's concerns about NSPI's reliance on fossil fuels:

> The utility's vulnerability to the fluctuating prices of imported fuel has created a new urgency for increased energy security through the use of domestic, renewable energy generation. It is our view that the Board should note where legislative or policy changes by government would help to achieve this objective.
>
> (NDP, Redacted Closing Submission, p. 14)

11.6.1 Findings

[627] The Board notes from its review of the evidence that NSPI has undertaken steps to address many of the issues raised by the EAC, including significant stakeholder consultation with respect to DSM, targeting increased sources of renewable energy such as wind from independent producers, and retrofitting its generation facilities to reduce air pollution and waste energy.

[628] In the Board's opinion, NSPI has undertaken concrete steps to address many of the concerns raised by the EAC, the NDP Caucus, GPI Atlantic and ECANS. While much work remains to be done, the Board is satisfied that NSPI is addressing these issues. The Board will continue to monitor the Company's progress. It should be noted that DSM and air emission controls will be the subject of separate hearings held by the Board in 2006.

11.7 Incentive Compensation Plan Review

[629] In its March 31, 2005 rate decision, the Board determined that NSPI's incentive compensation plan should be reviewed to determine whether it delivers an equal benefit to both shareholders and ratepayers, who now share the cost of the plan on a 50/50

basis. The Board directed NSPI to file a report within six months of its decision, such plan to be then reviewed by independent experts engaged by the Board.[224]

[630] NSPI's Incentive Compensation Report was filed with the Board on September 30, 2005. In response to NSDOE IR-91, the report was filed in this hearing.

[631] Avon submits that NSPI's Report is unresponsive to concerns raised by intervenors during the last rate case, in that the Company, according to Avon, has provided little more than a generalization of the benefits accruing to customers. Avon's concern is that the executive incentive plan is not sufficiently aligned with ratepayers' interests (i.e., at least not to the extent of 50%). In support of this concern, Avon refers, as an example, to the "balanced scorecard" for NSPI's Director of Energy Fuels and Risk Management, which was the subject of cross-examination during the hearing.[225]

[632] In light of its concerns, and the Board's directives arising out of the last rate decision, Avon notes that NSPI is forecasting to double the bonuses paid out in 2006 over those paid in 2005, with 50% of the maximum possible bonus award for 2006 being included in costs for the 2006 test year.[226] Avon questions whether such bonuses should be awarded in the context of NSPI's request for a significant rate increase for customers. It adds that the burden is on NSPI to demonstrate that these expenses are reasonable and prudently incurred.

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[224] Board Decision, March 31, 2005, para. 346

[225] Avon, Redacted Rebuttal Submission, pp. 17-18; Transcript, November 17, 2005, pp. 841-847

[226] Avon IR-9(d)-(f)

11.7.1 Findings

[633] The Board has engaged Lawrence N. Koppelman of Liberty to review NSPI's Incentive Compensation Report. His report was recently filed with the Board and has been forwarded to NSPI for their comment. Any issues arising from this review can be addressed in a future rate hearing. For the 2006 test year, the Board approves the amounts proposed by NSPI.

11.8 Non-Profit Intervenor Costs

[634] The Affordable Energy Coalition asks the Board for costs in this matter. In support of this request, it stated:

> 73. The Affordable Energy Coalition is a non-profit coalition of individuals and groups who work directly with low income Nova Scotians. These groups combined their efforts in a manner consistent with previous rulings of this Board, which had the effect of reducing hearing time and other costs.
>
> ...
>
> 75. Each of the members of the AEC is a non profit organization, and has no commercial interest in the outcome of these hearings. None of these groups receive funding to support public interest litigation or the costs of intervention in this rate application.
>
> ...
>
> 77. Low income Nova Scotians have a substantial interest in the application to increase rates by NSPI. The effect of a rate increase on low income residential consumers will be immediate and far ranging as it deepens already unsustainable energy burdens on this group of consumers.
>
> 78. It is submitted that the AEC acted responsibly and prudently in these hearings. The intervention on behalf of low income consumers combined the interests of several groups and it consciously avoided duplicating the evidence already presented or made available by other

> interveners in the matter. As such, it is submitted that the AEC has behaved in a responsible manner to incur only such costs as were necessary to complete the evidence before the Board concerning the issues in this application.
>
> 79. It is submitted that the arguments submitted by the AEC have contributed to the "better understanding" of the issues affecting low income residential customers in this application for a rate increase by NSPI.
>
> (AEC, Redacted Closing Submission, pp. 23-24)

11.8.1 Findings

[635] NSPI has not addressed the AEC's request for costs in its submissions. The Board directs NSPI to file its response to this request no later than April 20, 2006. AEC will have an opportunity to file additional written submissions on this issue no later than May 1, 2006. Following its review of the submissions, the Board will issue a ruling on this request.

11.9 General Demand Rate Class

[636] Robert Cook, President of the Nova Scotia Association of Health Organizations ("NSAHO"), made a presentation to the Board at the evening session on November 23, 2005. He outlined the mandate of his association and stated that it represents and provides services to the health organizations in the Province. The types of organizations NSAHO represents include hospitals, nursing homes, group homes, adult residential centres and home care support entities.

[637] Mr. Cook stated that NSAHO's reason for appearing at the hearing was the significant proposed rate increases, and the revenue/cost ratio ("R/C") for the General Demand class. He stated that the current R/C ratio for the General Demand customers is 108.75%, which is outside the Board's target range of 95% to 105% for all customers. He

outlined the impact this higher R/C ratio is having on NSAHO's members, based on the total current annual bill of approximately $20 million for these customers. He also pointed out that the R/C ratio for the General Demand class has been above 105% for some time and is causing hardship to NSAHO's members.

11.9.1 Findings

[638] In the Board's view, as set out in its 2002 and 2005 rate decisions, it is desirable to maintain, where reasonable, an R/C ratio between 95% and 105% for all classes. The Board continues to believe that it is fair and reasonable, in terms of the impact on other ATL customers, for the General Demand class to be gradually moved to an R/C ratio of 95% to 105%.

12.0 SUMMARY OF DISALLOWANCES AND ADJUSTMENTS

[639] NSPI, in its July 5, 2005 filing, projected a revenue requirement for 2006 of $1,003.7 million from above-the-line customers, which was $128.4 million higher than the 2005 Compliance Filing.

[640] NSPI illustrates the increases sought from customers, including the resulting revenue cost ("R/C") ratios and the total revenue requirement in the following table compiled by the Board:

		2006 Rate Application - July 5, 2005				
	Current Revenue	Costs	Proposed Revenues	Revenue Increase	Revenue % Increase	R/C Ratios
ABOVE-THE-LINE CLASSES						
Residential						
Total Residential	**$435.2**	**$512.6**	**$504.3**	**$69.1**	**15.9%**	**98.4%**
Commercial						
Small General	$25.9	$29.4	$30.1	$4.2	15.9%	102.3%
General Demand	$224.8	$237.2	$249.0	$24.2	10.8%	105.0%
Large General	$30.2	$36.0	$35.0	$4.8	15.9%	97.3%
Total Commercial	**$281.0**	**$302.6**	**$314.2**	**$33.2**	**11.8%**	**103.8%**
Industrial						
Small Industrial	$20.7	$23.5	$24.0	$3.3	15.9%	102.2%
Medium Industrial	$43.2	$49.7	$50.1	$6.9	15.9%	100.8%
Large Industrial	$59.9	$73.9	$70.2	$10.3	17.2%	95.0%
Total Industrial	**$123.8**	**$147.1**	**$144.3**	**$20.5**	**16.5%**	**98.1%**
Other						
Municipal	$13.4	$16.3	$15.5	$2.1	15.9%	95.4%
Unmetered	$21.9	$25.1	$25.4	$3.5	15.9%	100.9%
Total Other	**$35.3**	**$41.4**	**$40.9**	**$5.6**	**15.9%**	**98.8%**
Total A/L Classes	**$875.3**	**$1,003.7**	**$1,003.7**	**$128.4**	**14.7%**	**100.0%**
Total B/L Classes			**$146.4**			
Total All Classes			**$1,150.1**			
Exports			**$8.3**			
Miscellaneous			**$10.4**			
Total Revenue Requirement			**$1,168.8**			

[641] As the Board has outlined in this decision, a number of disallowances and adjustments have been made which reduce NSPI’s 2006 revenue requirement. These are set out below:

Disallowances and Adjustments	
ITEM	**DISALLOWANCES/ ADJUSTMENTS**
Imprudence disallowance - fuel costs	$15,700,000
Additional natural gas resale benefit	$35,800,000***
PTMT - fuel disallowance	$2,300,000
OM&G	$12,300,000
Load Reduction	$1,600,000
Cash working capital (Rate Base)	$1,400,000*
Long-term receivable (Rate Base)	($1,186,000)**
Total Disallowances and Adjustments	**$67,914,000**

*($29,400,000 - 12,250,000) x 8.21% WACC = 1,408,000

**Average increase in rate base of 14,450,000 x 8.21% WACC = 1,186,000

***NSPI proposed an additional natural gas resale benefit of $22.6 million as the estimated impact of the settlement with its supplier

[642] The Board understands that the $67.914 million in disallowances and adjustments listed above are estimates based on the evidence filed during the hearing. The Board directs NSPI, through the Compliance Filing, to confirm the actual reduction in revenue requirement which flows from this decision.

[643] As noted earlier, NSPI originally requested an increase in its revenue requirement of approximately $128.4 million from ATL customers. This request resulted in a proposed average increase for ATL customers of 14.7%, with an average increase of 15.9% for domestic customers. NSPI later indicated that the proposed increase would be reduced by about 2% due to the settlement with its natural gas supplier, announced November 21, 2005.

[644] The disallowances and adjustments directed by the Board and noted above, are expected to result in an approximate average rate increase of 8.6% for above-the-line customers. Domestic customers can expect a rate increase of approximately 8.9%. The increase in rates for ATL customers is effective March 10, 2006. The ELIIR and 2P-RTP rate shall be determined by NSPI in the Compliance Filing as set out in this decision. All other below-the-line rates are approved as set out in this decision. All BTL rates are effective January 1, 2006.

[645] As noted in prior rate decisions, the Board considers it desirable to maintain, where reasonable, an R/C ratio of 95% to 105%. The Board recognizes that the General Demand class category did not fall within the 95% to 105% R/C range in 2005, but it determined in its decision that it is fair and reasonable, in terms of the impact on other ATL customers, for this rate group to be gradually moved within the 95% to 105% R/C ratio. The Board continues to believe that the General Demand class should gradually be moved to an R/C ratio of 95% to 105%.

[646] The Board directs NSPI to base its adjustments in the Compliance Filing on the findings noted above.

13.0 FINANCIAL HEALTH OF NSPI

13.1 Submissions - NSPI

[647] In its evidence and submissions, NSPI repeatedly urged the Board to consider the financial health of the Company in assessing the rate application. In its Opening Statement, the Finance Panel cautioned that NSPI's customers would ultimately suffer from a possible credit rating downgrade faced by the Company:

> As the Board is aware from information provided directly and as part of this hearing, Nova Scotia Power is facing the very real prospect of a credit rating downgrade in the near future should the Company not be able to recover its fuel costs and improve its cash flow position. If these circumstances were not addressed, this would be a very significant event for the future of Nova Scotia Power with long-term implications for our customers. The Company is experiencing cash flow shortages today that are not sustainable if the Company is to continue as a financially viable utility.
>
> As a regulated investor-owned utility, we have a responsibility to both our customers and our shareholders. The continued financial strength of the utility is important to both parties. In the long run it is most important to our customers.
>
> Investors have choices about where to invest money. If NSPI is not viewed as providing a fair return compared to other utilities, NSPI will be limited in its access to capital. This would ultimately lead to higher costs, and in a worse case, inability to access fuel markets and provide appropriate customer service. It is our customers who would ultimately bear the brunt of a credit rating downgrade.
>
> (Exhibit N-170)

[648] This issue was further highlighted by Mr. Huskilson near the conclusion of the hearing:

> ... A year ago no one had anticipated such increases in world fuel prices or in that volatility. This creates a much greater risk for both us and for our customers, and uncertainty for all of us. Nova Scotia Power has paid a heavy penalty – perhaps heavier than anticipated -- for past actions, and I believe that a second fuel cost disallowance would create a very high risk that Nova Scotia Power would see its credit rating downgraded. That's certainly not in the best interests of customer because, you see, our customers are expecting us to invest in their energy future and that will require millions of dollars of future capital.
>
> (Transcript, December 1, 2005, p. 3052)

[649] NSPI indicates that its financial health has deteriorated, leading two of the three rating agencies that rate NSPI (Standard & Poor's and Moody's) to lower their outlook on NSPI from "stable" to "negative" .[227] The Company cautions that it risks a rating downgrade, observing that it would become the lowest-rated electric utility in Canada if it is downgraded one more notch by Standard & Poor's. According to Moody's, there are various factors which could lead to a downward rating, including the Company's inability to maintain sustainable credit metrics, its failure to receive timely and balanced regulatory decisions, its inability to manage its fuel price risk, and its increased reliance on short-term or floating rate debt.[228]

[650] In its evidence, NSPI referred the Board to various examples of comments provided by rating agencies about the financial health of the Company:

> The negative outlook reflects the weakening of the companies' financial profiles due to NSP's inability to fully recover its fuel costs through rate increases. The negative outlook also reflects Moody's concern that there may not be the regulatory willingness to address NSP's fuel price risk exposure through periodic rate applications or the adoption of a fuel price pass-through mechanism. Moody's also expects that increasing capital expenditure requirements over the medium term will cause NSP to have a negative trend for free cash flow over the next few years.
>
> (Moody's Investor Services, Global Credit Research Credit Opinion: Emera Inc., October 11, 2005; NSPI, Redacted Closing Argument, p. 52)

[651] Similar concerns were expressed even after NSPI reached a settlement with its supplier respecting its long-term natural gas agreement:

> Both Emera's and NSPI's financial profiles have been weakened by, among other things, under-recovery of increasing fuel costs at NSPI. Significant uncertainty remains regarding

[227] NSPI, Rebuttal Evidence, Exhibit N-153, pp. 54-55; Province IR-70 (Supplemental)

[228] Province IR-70 (Supplemental)

> the timeliness and fullness of future fuel cost recovery. Yesterday's announced gas pricing arrangement, therefore, will not serve to strengthen the utility's financial profits. Meaningful improvement in the company's business and financial profiles is reliant on favourable regulatory decisions in 2006.
>
> (Standard & Poor's, Bulletin, November 22, 2005, Exhibit N-221; NSPI, Redacted Closing Argument, p. 52)

[652] NSPI stresses the need for the Company to maintain an ability to secure capital investment for future projects. In its Closing Argument, it quoted Bonbright in support of this view:

> Professor Bonbright identifies the Capital-Attraction Standard as "one of the most prominent and most widely recognized functions of public utility rates":
>
>> By this standard, reasonable rates are rates adequate to yield revenues that will cover all legitimate operating expenses plus a return on investment sufficient to **maintain sound corporate credit and to attract required amounts of new capital. Rates below this level are deemed inefficient because, at least in the long run, they will not enable the company to live up to its obligation to service the community.** [Emphasis added in original]
>
> (NSPI, Redacted Closing Argument, p. 51)

[653] NSPI submits that a rating downgrade will have serious consequences for the Company, including higher borrowing and capital costs over the long-term as the Company refinances debt and attempts to raise new capital to support capital investment in facilities. Moreover, NSPI states that the most immediate impact of a credit downgrade will be its impact upon fuel procurement procedures and costs. It notes that a credit downgrade will impact credit limits with suppliers, impose less flexible payment terms, require deposits or

up-front payments, raise borrowing costs, increase fuel costs and, possibly, result in the inability to obtain fuel from certain suppliers.[229]

[654] Despite the assertion by intervenors that the risk of a downgrade must not deter the Board from denying costs which are not reasonably incurred, Mr. Huskilson underscored that the impact of any credit downgrade would ultimately be borne by NSPI's customers:

> A. (Huskilson) Well, if you're talking about bond ratings, it ultimately is an issue that the company has and also an issue for customers. And the reason that it's an issue for customers is because customers expect the company to make investments. And as the company makes investments, it has to raise money. And if it's unable to raise the money necessary to make those investments, then that will affect service. And that's the kind of thing that whether the -- it's very hard to separate the stakeholders of a company like a utility because, ultimately, all the stakeholders of the utility need the utility to be in a healthy situation and to be able to perform the functions and the service that it needs to provide.
>
> (Transcript, December 1, 2005, pp. 3198-3199)

13.2 Submissions - Intervenors

[655] A number of the intervenors questioned NSPI's assertion that the Company's financial health is in jeopardy. SEB refers to the evidence of Dr. Rosenberg, who disputes NSPI's claim that it is not financially healthy. After adjusting for the $18 million fuel disallowance incurred in the 2005 rate case, Dr. Rosenberg maintains that NSPI will still earn a return on equity of 9.36%, which is within the approved ROE band. This assertion was challenged by NSPI, which stated that the actual ROE for 2005 is expected to be 8.58%.

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[229] NSPI, Redacted Closing Argument, pp. 54-55

[656] In addition to Dr. Rosenberg's relatively optimistic view with respect to NSPI's 2005 ROE performance, Avon refers to other items which could potentially add to NSPI's 2005 earnings, including the Company's settlement with its natural gas supplier, the Company's receipt of a favourable court order issuing an attachment order with respect to its litigation with AMCI Traders respecting a claim of $11.2 million, and a $5 million saving from the 2005 Compliance Filing for interest expense as a result of the Company's ability to secure lower interest rates in issuing long-term debt.[230]

13.3 Findings

[657] The Board recognizes the importance of ensuring that NSPI remain on a sound financial foundation as it heads into the future. The Company's ability to attract capital, access fuel markets and control costs must not be compromised.

[658] In the view of the Board, there are various reasons to be confident about NSPI's future financial health. First, with respect to fuel, which is the most significant component of costs, the Board has approved what it considers to be an appropriate estimate of total fuel costs. The Board recognizes, of course, that any estimate of future costs is subject to error. However, based on the most current information available at the time of the hearing, there is reason to be confident that NSPI can meet the approved fuel budget, and perhaps even better it.

[230] Avon, Redacted Closing Submission, pp. 23-24

[659] The only material exception to the Company recovering its fuel costs in 2006 is the imprudence disallowance of $15,700,000. Since NSPI essentially enjoys the benefit of being a monopoly supplier of electricity in this Province, it is imperative that it only be able to recover its prudently incurred costs. Ratemaking principles and utility regulation require that costs incurred imprudently should not be borne by ratepayers.

[660] Having said that, the Board wishes to emphasize that the imprudence finding for the failings discussed in this decision will no longer have an impact upon NSPI's fuel budget. The Board is satisfied that NSPI has taken significant steps to improve its fuel procurement policies, incorporating a portfolio approach which will help dampen the impact of price volatility. This will allow NSPI to better achieve results falling within the parameters of its fuel budget, which is reflected in rates.

[661] While certain OM&G expenses have not been approved by the Board, it notes that the costs which were denied will not generally impair NSPI's existing operations, but, instead, will merely curtail the spending with respect to programs requested by NSPI (e.g., DSM, vegetation management, communications). A further result of this rate case is the Board's direction that an operations review of NSPI must be carried out. This review will critically examine NSPI's operations and help ensure the efficient allocation of its resources. This should ultimately yield positive results for NSPI customers and investors alike.

[662] The Board recognizes that the interests of customers and shareholders of NSPI are not mutually exclusive. They both benefit from a financially sound utility. In this

decision, the Board has strived to strike an appropriate balance between the interests of NSPI and its customers.

14.0 SUMMARY OF BOARD FINDINGS

14.1 Financial Health of NSPI

[663] In its evidence and submissions, NSPI repeatedly urged the Board to consider the financial health of the Company in assessing the rate application. NSPI indicates that its financial health has deteriorated, leading two of the three rating agencies that rate NSPI (Standard & Poor's and Moody's) to lower their outlook on NSPI from "stable" to "negative". The Company cautions that it risks a rating downgrade.

[664] NSPI submits that a rating downgrade will have serious consequences for the Company, including higher borrowing and capital costs over the long-term as the Company refinances debt and attempts to raise new capital to support capital investment in facilities. Moreover, NSPI states that the most immediate impact of a credit downgrade will be its impact upon fuel procurement procedures and costs. It notes that a credit downgrade will impact credit limits with suppliers, impose less flexible payment terms, require deposits or up-front payments, raise borrowing costs, increase fuel costs and, possibly, result in the inability to obtain fuel from certain suppliers.

[665] The Board understands the importance of ensuring that NSPI remain on a sound financial foundation as it heads into the future. The Company's ability to attract capital, access fuel markets and control costs must not be compromised.

[666] The Board recognizes that the interests of customers and shareholders of NSPI are not mutually exclusive. They both benefit from a financially sound utility. In this

decision, the Board has strived to strike an appropriate balance between the interests of NSPI and its customers.

14.2 Fuel Procurement Strategy

[667] The Board recognizes the effort expended by NSPI in implementing many improvements in its fuel procurement procedures, and in the Fuel Procurement Policies and Procedures Manual, in the relatively short period of time which has elapsed since the Board's 2005 rate decision.

[668] However, a number of deficiencies still remain. The Board directs that NSPI implement, as soon as possible, all the recommendations by Liberty set out in this decision, and that NSPI file a report by August 31, 2006, outlining the status of the recommendations which were implemented, and those recommendations, if any, which were not implemented. The Board further directs that NSPI liaise with Liberty in the implementation of these recommendations.

[669] Notwithstanding that the Manual is not finalized and has not received approval, NSPI must proceed with the implementation of its proposed fuel strategy. The Board expects NSPI to use its judgment both with respect to the changes it proposes to the Manual, and with respect to the implementation of the fuel strategy.

[670] In its March 31, 2005 decision, the Board directed NSPI to engage a fuel procurement expert with respect to coal acquisition. While the Board understands that NSPI has been diligently working to identify and employ such an individual, the Board

wishes to convey to NSPI its concern over the lack of progress in this very significant area of NSPI's operations. Accordingly, the Board directs NSPI to continue expeditiously with its efforts to obtain a solid fuel expert. Failing that, NSPI is directed to consider and evaluate other options which would permit it to acquire the necessary skills to enable it to acquire coal on a competitive basis in the international market. NSPI is directed to file a quarterly status report with the Board concerning this matter, commencing April 30, 2006.

14.3 Carryover of Imprudency

[671] The Board concludes that there is a continuing harm in 2006 as a result of NSPI's failure to implement a portfolio strategy commencing in 2002. The Board is satisfied that, for the same reasons as the Board found in its decision of March 31, 2005, NSPI had an opportunity at that time to begin implementing an appropriate fuel procurement strategy. If NSPI had taken advantage of that opportunity, as it should have done, it would have been able to obtain coal for 2006 at costs significantly less than those which it now forecasts for the 2006 test year. The additional expense involved should not be borne by the ratepayers because it was imprudently incurred. The Board sets the imprudence disallowance for the 2006 test year at $15,700,000.

[672] To avoid any uncertainty going forward, the Board wishes to make it clear that the impact of NSPI's past imprudence for the failings discussed in this decision is now spent and will not extend beyond the 2006 test year. This is because, even if NSPI had entered into a multi-year contract in 2002 and 2003, as the Board considers it should have

done, the Board is satisfied that such contract would have likely run its course by the end of 2006.

14.4 Long-Term Contract

[673] In April of 2005, NSPI entered into its first multi-year contract to acquire low sulphur import coal. The Board finds that the April 2005 contract was not an imprudent transaction.

14.5 Affiliate Activity

[674] The Board is not prepared at this time to require NSPI to assume direct responsibility for selling its surplus natural gas. However, the Board will monitor the transactions and the relationship between NSPI and the company selected to handle NSPI's natural gas, particularly if the arrangement should be with an affiliated company.

[675] The Board directs that NSPI conduct a study to determine the feasibility of establishing an in-house capability to sell its own gas. The study shall be filed with the Board by August 31, 2006.

[676] The Board accepts the recommendation of Liberty to implement a process of detailed, periodic audits of affiliate transactions. Due to Liberty's extensive knowledge of NSPI, the Board will retain Liberty to carry out the first audit. During 2006, the Board will request Liberty to prepare a detailed work plan for the first audit, including the estimated time and budget, as well as an appropriate commencement date. The Board directs that

the work plan be filed with the Board by June 30, 2006 for Board approval. NSPI will be consulted during this process and its opinions solicited. The Board, in planning the commencement date for the first audit, will give consideration to other time commitments which may be facing NSPI.

[677] The detailed audit of affiliate transactions is not meant to replace the annual reporting required under the Code of Conduct.

14.6 Point Tupper Marine Terminal

[678] The Board has determined that NSPI is not entitled to include, in its fuel expense, a capital recovery charge of $2.3 million with respect to the Point Tupper Marine Terminal.

[679] At a future date, NSPI may apply to have the PTMT included in rate base. Should NSPI make such an application, the Board is prepared to consider at that time whether an allowance should be made for deferred capital charges.

14.7 Natural Gas Resale Benefit

[680] During the hearing, NSPI announced it had reached a settlement with its supplier on the future pricing and supply arrangements of natural gas. As a result of the settlement, the Company expects to achieve better results on the resale of its natural gas than originally forecast when it filed its application on July 5, 2005. The Board finds that it is reasonable to adopt a gas resale benefit of $35.8 million higher than that contained in

the original filing of July 5, 2005, thereby decreasing NSPI's original fuel budget by the same amount.

[681] The Board determines that no deferral mechanism or reserve fund should be implemented at this time. In a test year where customers are facing a significant rate increase, the Board is loath to defer any potential benefits from the gas resale benefit to a future test year.

[682] Some intervenors asked the Board to consider whether the benefits of the natural gas settlement between NSPI and its supplier were appropriately allocated between the Company's customers and shareholders.

[683] Having reviewed the terms of the negotiated settlement, the testimony related to it, and the submissions of the parties, the Board is persuaded that the settlement reached with the supplier benefits NSPI's customers and that there was a fair and reasonable allocation of the benefits accruing under the settlement between shareholders and customers.

14.8 Fuel Costs

[684] With the exception of the items noted above, the Board is of the view that there should be no further adjustment to NSPI's fuel budget. The Board sets NSPI's fuel budget for the test year at $425,100,000.

14.9 Return on Equity

[685] In the 2005 rate decision, the Board approved a return on equity at 9.55% for the purpose of setting rates, with an earnings range set at 9.30% to 9.80%. The Board has made no change to return on equity.

14.10 Capital Structure

[686] In the 2005 rate decision, the Board approved an increase in the common equity ratio for ratemaking purposes from 35% to 37.5%. The Board is satisfied that the common equity ratio should be maintained at 37.5%.

14.11 Rate Base

[687] In the 2005 rate decision, the Board directed that NSPI use a return on rate base methodology for its next rate application. The main issue which arose from the adoption of this approach was calculating the cash working capital ("CWC") allowance.

[688] While the Board determined that HST should be included in the calculation of the CWC allowance, it has excluded other items like the securitization of accounts receivable, interest expense and preferred dividends. The Board has also made adjustments to some of the lead/lag assumptions to be incorporated into the calculation.

[689] Based on the above findings, the Board has set the CWC allowance for the 2006 test year at $12.25 million, which has the effect of reducing the rate base by $17.15 million ($1.4 million reduction in the revenue requirement).

[690] The only other adjustment to rate base which appears to be justified on the evidence is to account for the increase in the long-term receivable resulting from the settlement between NSPI and its natural gas supplier. The Board approves an increase in the rate base of $14.45 million to reflect the difference between the long-term receivable estimated in the original rate filing and the amount estimated following the settlement.

[691] The amount of the 2005 Q1 tax deferral has not been finally determined as yet and, in the Board's view, it would be premature to include any amount in rate base at this time.

14.12 Operating, Maintenance and General Expenses (OM&G)

[692] The Board approves an increase in Operating, Maintenance and General expenses from $182.0 million (2005C) to $197.5 million for the 2006 test year, a $15.5 million increase. NSPI had requested an increase of $27.8 million.

(a) Power Production

[693] All the proposed Power Production increases are approved except a disallowance relating to succession planning. In the view of the Board, an additional amount of $1.0 million per year (rather than $1.8 million) should adequately address this group's succession planning issues for the 2006 test year.

(b) Customer Operations

[694] With respect to Customer Operations, the Board approves a proposed cost increase for enhanced storm response, which reflects an increase from $1.4 million

presently included in rates to $5.4 million allocated for the 2006 test year. The Board is mindful that NSPI has greatly enhanced its storm response activities since major storm events like Hurricane Juan and the November 2004 storm.

[695] The Board has reduced NSPI's proposed increase respecting succession planning for power line technicians from $500,000 to $300,000.

[696] In relation to vegetation management, NSPI requested an increase from $5.2 million to $10.4 million in spending. The Board approves a total of $6.8 million ($3.2 million for the transmission system and $3.6 million for the distribution system), an increase of $1.6 million over the amount currently reflected in rates.

[697] NSPI has also requested an additional $1.3 million to improve communication with its customers. The Board approves the requested amount of $500,000 with respect to enhancements to the HVCA and IVR telephone systems, as well as the testing of the systems. However, the Board is not satisfied that NSPI's request for the remaining $800,000 is warranted particularly in the context of the significant rate increase being requested by the Company. It reduces from $800,000 to $300,000, the amount requested with respect to increased customer research, additional proactive communications and increased quality assurance in the customer service area.

(c) Corporate Support Group

[698] With respect to the Corporate Support Group (with the exception of DSM which is discussed below), the Board denies the Company's request for a $492,000 increase for advertising activities carried out by the Investor and External Relations group.

It is the view of the Board that such expenses related to promoting the Company's corporate image and enhancing its goodwill in the community should not be included in the revenue requirement being sought from customers.

[699] The Board approves the $1.6 million expenditure increase under Regulatory Affairs respecting a 2007 rate case which NSPI expects to file in 2006, as well as the $400,000 increase for the 2006 Board assessment.

[700] New governance and audit regulations adopted by the OSC will result in higher regulatory compliance costs. The Board directs that half of the proposed net increase be deferred to 2007, resulting in a net increase approved for this activity of $235,000 ($470,000 less 50% recovered from Emera).

(d) Corporate Adjustments

[701] With respect to Corporate Adjustments, the Board denies NSPI's proposed deferral of $2.0 million associated with regulatory expenses incurred by the Company in 2005, including the cost of the rate hearing held in 2005 and the increased 2005 Board assessment. In the Board's opinion, it is not reasonable to burden ratepayers with the cost of two rate hearings and two increased Board assessments in the same test year, which would be the case were the Board to permit NSPI to roll the 2005 costs into 2006.

[702] The Board approves the remainder of the Corporate Adjustments sought by NSPI, including an increase relating to pension expense from $26.0 million to $31.7 million for the 2006 test year. This represents an increase of $5.7 million in pension expense, which was supported by an actuarial report outlining the basis for this increase.

14.13 Operations Review

[703] In past decisions, the Board has expressed concern about the control of OM&G expenses by NSPI. Following its review of the evidence in this hearing, the Board continues to be concerned about the magnitude of the increase sought by NSPI for OM&G expenses, particularly since it accompanies NSPI's request for a very significant rate increase.

[704] Accordingly, the Board directs that an operations review be carried out on NSPI's operations. The review shall encompass a detailed examination of NSPI's organizational structure, its level of OM&G expenditures, and any other pertinent areas which may come to light, with a view to determining whether cost savings and operational efficiencies can be achieved. NSPI is directed to prepare the terms of reference for the operations review and submit them to the Board for approval by May 31, 2006. The terms of reference shall also set out the procedures for identifying and selecting the firm or person who will perform the operations review.

[705] The Board directs NSPI to include detailed five year forecasts of OM&G costs in all future rate applications.

14.14 Demand Side Management

[706] The Board commends NSPI in its effort in preparing a DSM Plan. All intervenors and consultants generally agree that DSM is important and that it ought to be pursued. However, the Board considers that approval of the Plan, as submitted by NSPI,

is premature at this time. The Plan needs additional design work and resources. NSPI customers expect that any DSM program should be carefully designed to ensure its maximum impact, and effectively implemented.

[707] The Board approves $550,000 in additional funds (and not the $5 million requested by NSPI) to retain an outside consultant and to complete the Plan's design and development. NSPI is directed to prepare the terms of reference for the consultant and submit them to the Board for approval no later than April 15, 2006. The process of retaining and selecting the consultant will be monitored by the Board. The Board orders that NSPI complete the DSM Plan and file it with the Board no later than June 30, 2006, utilizing the assistance of the Board approved consultant.

[708] The Board orders that a separate hearing on DSM be held in the second half of 2006.

14.15 Depreciation

[709] The Board approves the resumption of the second year phase-in of the four year increase of depreciation rates in the 2006 test year.

14.16 Annually Adjusted Rates/Below-the-Line Rates

[710] The Board has not received any evidence in opposition to NSPI's proposed GRLF rates and they have been calculated as in previous years. Accordingly, the 2006 GRLF rates proposed by NSPI are approved by the Board effective January 1, 2006.

[711] There were no intervenor submissions on either the proposed increase in the 1P-RTP adders or the proposed amendment to the tariff. The Board approves the adders and the tariff addition proposed by NSPI.

[712] The Board has decided that ELIIR will be substantially redesigned for 2007. The redesign will affect the 2P-RTP rate used in conjunction with ELIIR.

[713] In light of the unanimous support for the language in the 2P-RTP rate at the time it was approved, and the likelihood of substantial change effective January 1, 2007, the Board has decided not to approve any changes in the tariff wording at this time. The Board approves the 2P-RTP rate in its current form effective January 1, 2006.

[714] The Board concludes that the FP-DSM/DR rate proposed by SEB is not cost based and would create an undue burden on ATL customers. Accordingly, the Board is not prepared to approve the FP-DSM/DR rate.

[715] It is clear to the Board that ELIIR is not working as it was originally intended to by both NSPI and SEB. Therefore, the Board will hold a separate hearing in 2006 to consider a replacement for ELIIR, which will become effective January 1, 2007. The Board directs NSPI to file an application for a new rate to replace ELIIR, after consultation with its customers, no later than June 30, 2006.

[716] For the current year, the Board has been presented with two approaches for setting the energy charge in ELIIR. NSPI supports the use of the formula in the existing tariff. The Board understands that Dr. Stutz recommends beginning with the LIR - that is the Large Industrial Rate at an 85% load factor, less the transformer ownership credit and

the value of the interruptible supply credit of $3.43 per month per kVa. Dr. Stutz then subtracts the value of economic interruptibility, which he calculated at $8.43 per MWh. Each of these approaches has strengths and limitations. Dr. Stutz's approach is conceptually correct, but does not provide a fully developed alternative for ELIIR. To give weight to each approach, the Board directs NSPI to set the ELIIR energy charge by averaging the results produced by the two approaches.

[717] In setting the ELIIR energy charge, the Board directs NSPI to use the fuel budget and all other items having an impact on ELIIR, as approved in this decision. The Board also directs NSPI to iterate its rate calculations, to ensure consistency between the LIR charges used to set ELIIR and those to be paid by customers on the LIR rate.

[718] The Board has directed NSPI to develop and file a replacement for ELIIR. Both NSPI and SEB have agreed that Dr. Stutz's approach to the development of such a replacement—beginning with a firm rate and then specifying credits for interruptibility—has merit. While the Board concurs, it would be prepared to consider other viable options which may be developed.

[719] NSPI proposed to add Special Condition 5 to the ELIIR tariff, the purpose of which is to require customers to file an hourly demand forecast on a day-ahead basis. Because the current version of ELIIR is about to be replaced, the Board will not approve any changes in the present tariff language. Upon filing, the Board will approve, effective January 1, 2006, the interim ELIIR rate calculated in accordance with this decision.

14.17 Load Forecast

[720] The Board is not persuaded that NSPI's manual adjustment to its load forecast should be approved. The Board concludes that denying the DSM-related load forecast reduction should increase variable costs, while corresponding revenues from electricity sales should increase. The impact of this finding is estimated to result in a net reduction of $1.6 million in the revenue requirement.

[721] The Board directs that NSPI file its report on the progress of improvements to its load forecasting methodology by December 29, 2006. This extension of the filing deadline should allow NSPI to incorporate its response to DSM-related load reduction issues.

14.18 Unmetered Rates

[722] The Board directs that a cost of service study be conducted as proposed by NSPI with respect to the Unmetered Class. The study shall include a review of the appropriateness of the current weighting factor and a review of the rate base, including assets, assigned to the Unmetered Class. The study should indicate a breakdown of costs and rate base by municipality. The cost of service study results shall be filed with the Board by July 31, 2006.

[723] The Board directs that the current weighting factor of 5.0 should remain in effect for the 2006 test year.

14.19 Miscellaneous Charges

[724] The Board approves the proposed increases to miscellaneous charges sought by NSPI, limiting the proposed increase to the average rate increase for ATL customers. In the event such increases result in a charge which exceeds the cost of delivering the service, the charge must be capped at the actual cost.

14.20 Low Income Consumers

[725] The AEC submits that the Board has a statutory obligation to protect the public interest by ensuring that the services provided by NSPI are affordable for its customers, including low income customers. Dalhousie Legal Aid appealed the Board's 2005 rate decision respecting such issues. The appeal is set to be heard by the Nova Scotia Court of Appeal. The Board considers it prudent to await the disposition of the appeal before it undertakes any further review of the issues raised by the AEC.

14.21 Pole Attachment Fees

[726] The setting of the pole attachment fee, as well as the scope of costs recovered under that rate and under "make-ready" charges, were canvassed by the Board in its decision on such issues dated January 24, 2002. The Board is satisfied that NSPI's allocation of costs is in accord with that decision and that the Company's proposed rate increase does not result in a duplication of the revenue earned from pole attachment fees and "make-ready" charges.

14.22 Renewable and Environmentally Sustainable Energy

[727] Some of the intervenors asked the Board to consider environmental issues in assessing NSPI's application for a rate increase. While much work remains to be done, the Board is satisfied that NSPI is addressing these issues. The Board will continue to monitor the Company's progress. It should be noted that DSM and air emission controls will be the subject of separate hearings held by the Board in 2006.

14.23 Incentive Compensation Plan Review

[728] In its March 31, 2005 rate decision, the Board determined that NSPI's incentive compensation plan should be reviewed to determine whether it delivers an equal benefit to both shareholders and ratepayers. NSPI's Incentive Compensation Report was filed with the Board on September 30, 2005.

[729] The Board has engaged Liberty to review NSPI's Incentive Compensation Report. Any issues arising from this review can be addressed in a future rate hearing.

14.24 Non-Profit Intervenor Costs

[730] The Affordable Energy Coalition asks the Board for costs in this matter. NSPI has not addressed the AEC's request for costs in its submissions. The Board directs NSPI to file its response to this request no later than April 20, 2006. AEC will have an opportunity to file additional written submissions on this issue no later than May 1, 2006. Following its review of the submissions, the Board will issue a ruling on this request.

14.25 General Demand Rate Class

[731] As set out in its 2002 and 2005 rate decisions, the Board considers it desirable to maintain, where reasonable, an R/C ratio between 95% and 105% for all classes. The Board continues to believe that it is fair and reasonable, in terms of the impact on other ATL customers, for the General Demand class to be gradually moved to an R/C ratio of 95% to 105%.

14.26 Disallowances and Adjustments/Rate Increase

[732] The Board has made disallowances and adjustments totalling $67,914,000, which will result in a reduction of a corresponding amount for NSPI's test year revenue requirement. This, in turn, is expected to result in an average rate increase of approximately 8.6% for above-the-line customers, with an estimated rate increase of approximately 8.9% for domestic customers. The increase in rates for above-the-line customers is effective March 10, 2006. All below-the-line rates will be effective January 1, 2006.

An Order will issue accordingly.

DATED at Halifax, Nova Scotia, this 10th day of March, 2006.

____
John A. Morash, Panel Chair

____
Roland A. Deveau, Member

____
Kulvinder S. Dhillon, Member

APPENDIX - A

List of Witnesses

On behalf of	Witness
NSPI	Chris Huskilson Ralph Tedesco Robert Boutilier Alan Richardson Daniel Muldoon Mark Sidebottom Ralph Janega Emily Medine James Taylor Daniel Walton Kathleen C. McShane Zeda Redden Greg Blunden Nancy Tower
BOARD COUNSEL	John B. Adger, Jr. John Antonuk Donald T. Spangenberg Lawrence N. Koppelman Dr. John Stutz
AVON et al.	Dr. Manfred Raschke Mark Drazen
STORA ENSO & BOWATER MERSEY	Richard Marston Colin V. Gubbins Sharon Hennings James Selecky Dr. Alan Rosenberg
CONSUMER ADVOCATE	Nancy Brockway
EVENING SESSIONS (November 23, 2005 and November 24, 2005)	Mark Parent, MLA, Kings North, Kings County Ronald Coleman, on behalf of GPI Atlantic David Boudreau, General Manager - RuSh Communications Chris Brown - Nova Scotia Federation of Agriculture Michael Moeller, Antigonish - on his own behalf Mel Boutilier, Exec. Dir. Parker Street Food and Furniture Bank Joan Jessome, President, NS Gov't & General Employees Union Ceilidh Auger-Day - Ecology Action Centre Peter Nestman - NS Association of Health Organizations Warden Richard Cotton, President, Union of NS Municipalities Joan Massey, MLA, Dartmouth East NDP Caucus Eastern Shore Sid Prest, Candidate, Eastern Shore, NDP Caucus Brian Butler, Resident of Fall River

Paul Pettipas, CEO Home Builders Association
Dave Wright, on his own behalf
Billy Petit, on his own behalf
Jim DeWolfe, MLA, Pictou East
Brooke Taylor, MLA , Colchester-Musquodoboit Valley
Hon. Murray Scott, MLA, Cumberland South

APPENDIX - B

List of Formal Intervenors

Affordable Energy Coalition	Megan Leslie and Claire McNeil
Avon et al: Avon Valley Greenhouses Ltd. Canadian Salt Company Limited Cerescorp Company CKF Inc. Copol International Ltd. Council of Nova Scotia University Presidents Crown Fibre Tube Inc. Halifax Grain Elevator Limited The Halifax Herald Limited High Liner Foods Inc. Imperial Oil Limited Intertape Polymer Inc. J.D. Irving Ltd., Saw Mills Division Maritime Paper Products Ltd. Michelin North America (Canada) Inc. Minas Basin Pulp & Power Company Ltd. Oxford Frozen Foods Limited Statia Terminals Canada Incorporated Trentonworks Limited	Robert Grant, Q.C. and Nancy Rubin
Barrington Wind Energy Limited	Erik Twohig
Canadian Manufacturers & Exporters	Sirje Weldon and Robert Patzelt
Consumer Advocate	John Merrick, Q.C. and William L. Mahody
Ecology Action Centre	Anne Warburton
Electricity Consumers Alliance of Nova Scotia	John Woods, P.Eng.
GasWorks Energy Corp.	Dwight Jeans and John Reynolds, P.Eng.
GPI Atlantic	Ronald Colman, PhD. and Judith Lipp
Halifax Regional Municipality	Mary Ellen Donovan, Cathie O'Toole and Julian Boyle
Heritage Gas Limited	Marilyn P. Wappel and Chris Smith
Dr. Larry Hughes, PhD	
Liberal Caucus Office (Nova Scotia)	Danny Graham, MLA and David Macrury
Town of Lunenburg	Norman A. Mossman

Municipal Electric Utilities of NS Co-op	Donald Regan and Albert Dominie
NAAL	Anthony Marsh, C.A.
New Democratic Party Caucus Office	Howard Epstein, MLA, Paul Black and Lorraine Glendenning
Province of Nova Scotia - Dept. of Energy	Stephen T. McGrath, Allan L. Crandlemire and Scott McCoombs
RuSh Communications Ltd.	David Boudreau
Stora Enso Port Hawkesbury Limited and Bowater Mersey Paper Company Limited	George T.H. Cooper, Q.C. and David S. MacDougall

APPENDIX - C

SUMMARY 2006 Cash Working Capital Requirement (Dollars in Millions)					
Category	**Lag Days (a)**	**Net Lag Days Rev Lag - (a)**	**% of Year (b)/365**	**Annual Cost (d)**	**CWC (c) x (d) (e)**
NSPI					
Revenue lag	42				
Labour	15	27	7.40%	$119.3	$8.8
Non-labour operating	45	(3)	(0.82)	90.5	(0.7)
Fuel & purchased power	30	12	3.29	479.0	15.7
Grants in lieu of taxes	(91)	133	36.44	32.6	11.9
Income taxes	30	12	3.29%	84.4	2.8
Total					**38.5**
Less customer deposits					(7.0)
CWC requirement					$31.5
DRAZEN					
Revenue lag	19.2				
Labour	21	(1.8)	(0.3%)	$119.3	$(0.6)
Non-labour operating	50	(30.8)	(8.4)	90.5	(7.6)
Fuel & purchased power	29.5	(10.3)	(2.8)	479.0	(13.5)
Grants in lieu of taxes	(91)	110.2	30.2	32.6	9.8
Income taxes	53	(33.8)	(9.3)	84.4	(7.8)
Interest on long-term debt	91.2	(72.0)	(19.7)	90.0	(17.8)
Preferred dividends	45.6	(26.4)	(7.2)	14.1	(1.0)
HST		(45.0)	(12.3)	75.7	(9.3)
Total					**(47.8)**
Less customer deposits					(7.0)
CWC requirement					($54.8)
SELECKY					
Revenue lag	22.8				
Labour	15	7.8	2.1	$119.3	2.5
Non-labour operating	45	(22.2)	(6.1)	90.5	(5.5)
Fuel & purchased power	30	(7.2)	(1.9)	479.0	(9.4)
Grants in lieu of taxes	(91)	68.2	18.7	32.6	6.1**
Income taxes	30	(7.2)	(1.9)	84.4	(1.7)
Interest (long & short-term debt)	82.7	(59.9)	(16.4)	101.3	(16.6)
Preferred dividends	45.6	(22.8)	(6.2)	14.1	(0.9)
Total					**(25.6)**
Less customer deposits					(7.0)
CWC requirement					(32.7)

* Error in Selecky's calculation

Note: The figures calculated above are then averaged with the calculation for the 2005 F, resulting in an average CWC requirement quoted by the parties.

Conservation & Energy Efficiency Plan 2006 - Detailed Summary Table

	Plan Elements		Residential			Commercial			Industrial			Totals	
			2005 Expenditure $	2007 GWh Savings	Notes	2006 Expenditure $	2007 GWh Savings	Notes	2006 Expenditure $	2007 GWh Savings	Notes	2006 Expenditure $	2007 GWh Savings
NSPI Led	1	Lighting	$980,000	32.65	1	$290,000	3.41	8	$0	0.00		$1,270,000	36.06
	2	Price Awareness	$295,200	4.72	2	$73,000	1.08	9	$0	0.00		$368,200	5.80
	3	Workshops	$311,250	3.60	3	$201,000	2.30	10	$77,750	0.90	13	$590,000	6.80
	4	Youth Education	$558,750	4.80	4	$149,000	1.13	11	$37,250	0.20	14	$745,000	6.13
Partner Led	5	Leveraging Partnerships	$560,000	9.83	5	$163,000	2.59	12	$0	0.00		$723,000	12.42
	6	EnerGuide For Houses	$497,500	2.67	6	$0	0.00		$0	0.00		$497,500	2.67
	7	EnerGuide For New Houses	$150,000	1.70	7	$0	0.00		$0	0.00		$150,000	1.70
Development of Future Programs	8	Pricing Design	$75,000	0.00		$90,000	0.00		$135,000	0.00		$300,000	0.00
	9	Other Future Programs	$297,300	0.00		$100,000	0.00		$35,000	0.00		$432,300	0.00
		Plan Totals	$3,725,000	59.97		$1,066,000	10.51		$285,000	1.10		$5,076,000	71.58

Notes:

1a	25% of homes use 4 CFL's, (.25 x 393,078 home x 4 CFLs/homes x 45 W/CFL x 5 hr/d x 365 day/yr x 1 GW/1,000,000,000W = 32.28 GWh)
1b	0.5% of homes use 2 LED night lights (.005 x 393,078 x 2 lights x 4.7 W/light x 9 hr/day x 365 day/yr x 1 GW/1,000,000,000 = 0.06 GWh)
1c	Holiday LED promotion results in 12,500 sets of lights being replaced (12,500 sets x 123 W/set x 200 hr/season x 1 GW/1,000,000,000W = 0.31 GWh)
2	3% of homes save 400 kWh/y (.03 x 393,078 x 400 kWh x 1 GW/1,000,000kW = 4.72 Gwh)
3	2000 homes save 1800 kWh/y (2000 homes x 1800 kWh/home x 1 GW/1,000,000kW = 3.6 Gwh)
4	6000 homes save 800 kWh/y (6000 x 800 kWh x 1 GW/1,000,000kW = 4.8 Gwh)
5	25% of homes save 100 kWh/y (.25 x 393,078 homes x 100 kWh/home x 1 GW/1,000,000kW = 9.83 GWh)
6a	425 homes save 4017 kWh/y in heating (425 x 4017 kWh/y x 1 GW/1,000,000kW = 1.71 GWh)
6b	2400 homes save additional 400 kWh/y (2400 x 400 kWh/y x GW/1,000,000kW = 0.96 GWh)
7	250 new homes save 6800 kWh/y in heating (250 x 6800 kWh/y x 1 GW/1,000,000kW = 1.70 GWh)
8a	3000 Businesses install 8 CFL's (3000 x 8 CFLs/business x 45 W/CFL x 10 hr/day x 5 day/wk x 52 wk/yr x 1 GW/1,000,000,000W = 2.81 GWh)
8b	1000 Businesses install 2 LED Exit Signs (1000 x 2 x 300 kWh x 1 GW/1,000,000kW = 0.60 GWh)
9	900 Businesses save 1200 kWh/y (900 x 1200 kWh x 1 GW/1,000,000kW = 1.08 GWh)
10	1150 Buisnesses save 2000 kWh/y (1150 x 2000kWh x 1 GW/1,000,000kW =2.3 GWh)
11	600 Buisnesses save 1875 kWh/y (600 x 1875 kWh x 1 GW/1,000,000kW = 1.13 GWh)
12	15% of Buisnesses save 575 kWh/y (.15 x 30,000 Buisnesses x 575 kWh/Business x 1 GW/1,000,000kW = 2.59 GWh)
13	75 Industrials save 12,000 kWh/y (75x 12,000 kWh/y x 1 GW/1,000,000kW = 0.90 GWh)
14	60 Industrials save 3,350 kWh/y (60 x 3350 kWh/y x 1 GW/1,000,000kW = 0.20 GWh)

Appendix - D

Application for Approval of Certain Revisions to its Rates, Charges and Regulations
NSUARB-NSPI-P-881, March 2005

DECISION | **NSUARB-NSPI-P-881**
2005 NSUARB 27

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION by **Nova Scotia Power Incorporated** for approval of certain Revisions to its Rates, Charges and Regulations

BEFORE:

Margaret A. M. Shears, Vice-Chair
Kulvinder S. Dhillon, P. Eng., Member
John A. Morash, C.A., Member

COUNSEL:

NOVA SCOTIA POWER INCORPORATED
James L. Connors, Q.C.

AVON VALLEY GREENHOUSES LTD., ***et al.***
Robert G. Grant, Q.C.
Nancy G. Rubin
Mark Freeman

CANADIAN MANUFACTURERS & EXPORTERS
J.D.R. (Dick) Smyth, P. Eng.

DALHOUSIE LEGAL AID SERVICE
Claire McNeil

ECOLOGY ACTION CENTRE
Anne Warburton

ELECTRICITY CONSUMERS ALLIANCE OF NOVA SCOTIA
John Woods, P. Eng.

GASWORKS ENERGY CORP.
John Reynolds, P. Eng.
Dwight Jeans

HALIFAX REGIONAL MUNICIPALITY
Mary Ellen Donovan

LIBERAL CAUCUS OFFICE (NOVA SCOTIA)
Diana Whalen
Jim Murphy

MUNICIPAL ELECTRIC UTILITIES OF NOVA SCOTIA CO-OPERATIVE
Albert Dominie

NEW DEMOCRATIC PARTY CAUCUS OFFICE (NDP)
Howard Epstein
Paul Black

PROVINCE OF NOVA SCOTIA
Stephen T. McGrath
Jeannine Lagassé

STORA ENSO PORT HAWKESBURY LIMITED and **BOWATER MERSEY PAPER COMPANY LIMITED**
George T. H. Cooper, Q.C.
David MacDougall
Mike Simms

HEARING DATES: November 16-30, 2004 and December 1-3, 2004
Settlement Agreement hearing - January 13-14, 2005

FINAL SUBMISSIONS: January 21, 2005

LIST OF WITNESSES: APPENDIX - A

LIST OF INTERVENORS: APPENDIX - B

BOARD COUNSEL: S. Bruce Outhouse, Q.C.
Richard Melanson

DECISION DATE:	**March 31, 2005**
DECISION:	**Settlement Agreement not accepted; Requested Revenue Requirement Increase of approximately $104 million reduced to approximately $34 million; Proposed average rate increase for above-the-line customers of 12.4% reduced to approximately 5.3% with a 6.1% increase for most above-the-line rates, including rates for domestic customers, effective April 1, 2005; Annually Adjusted Rates to increase by 10.4% effective January 1, 2005.**

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APPENDICES

1.0 INTRODUCTION

[1] This decision is further to a public hearing conducted by the Nova Scotia Utility and Review Board (the "Board") over 16 days between November 16, 2004 and January 14, 2005, in the matter of an application by Nova Scotia Power Incorporated ("NSPI", the "Company", the "Utility") for approval of revisions to its Rates, Charges and Regulations. Following the conclusion of the rate hearing on December 3, 2004, the Company filed a Settlement Agreement, between it and several of the intervenors, on December 15, 2004. The hearing was reconvened on January 13 and 14, 2005 to consider this proposal.

[2] NSPI is a regulated public utility and is the successor to Nova Scotia Power Corporation, a Crown Corporation which was privatized in 1992. As of January 1, 1999, NSPI became the principal subsidiary of Nova Scotia Power Holdings Incorporated, now known as Emera Incorporated ("Emera").

[3] NSPI is engaged in the production and supply of electrical energy. It distributes electricity through a province-wide system and, as at December 31, 2003, served approximately 460,000 customers, including six municipal electric utilities. Its revenues for the year 2003 were $896 million and its total assets, as at December 31, 2003, were $3 billion.[1]

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[1]Exhibit N-7, Tab 1, pp. 18-23

[4] In its revised application, dated June 23, 2004, NSPI requested an increase in rates to meet its proposed revenue requirement. It has used its estimated expenses for 2005 as the test year for ratemaking purposes. The proposed rate increases result in an average overall increase of 12.4% across all classes. Certain customers would experience rate increases considerably in excess of this amount. NSPI also requests approval of a return on common equity in a range of 10.2% to 11.2%, with a common equity component of its capital structure of 37.5%. In addition, NSPI proposes a Fuel Adjustment Mechanism ("FAM") to provide for a means by which changes in fuel costs experienced by the Utility would be passed through to customers automatically without the need for a hearing.[2] NSPI's application also includes changes to a number of its regulations, including increases in miscellaneous charges.

[5] The public hearing was duly advertised in accordance with **Sections 64** and **86** of the **Public Utilities Act** ("the **Act**") R.S.N.S. 1989, c. 380, as amended, which read as follows:

> **Approval of schedule of rates and charges of utility**
>
> **64 (1)** No public utility shall charge, demand, collect or receive any compensation for any service performed by it until such public utility has first submitted for the approval of the Board a schedule of rates, tolls and charges and has obtained the approval of the Board thereof.
>
> **Filing with Board**
>
> **(2)** The schedule of rates, tolls and charges so approved shall be filed with the Board and shall be the only lawful rates, tolls and charges of such public utility until altered, reduced or modified as provided in this Act. R.S., c. 380, s. 64.

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[2] Exhibit N-1, Tab 1, pp. 3-4

Notice of hearing of application for rate changes

86 Notice of the hearing of any application, for the approval of or providing for an increase or decrease in the rates, tolls and charges of any public utility, shall be given by advertisement in one or more newspapers published or circulating in the cities, towns or municipalities where such changes are sought, for three consecutive weekly insertions preceding the date of said hearing, unless otherwise ordered by the Board. R.S., c. 380, s. 86.

[6] Thirty-seven formal intervenors responded to NSPI's application, all but two in opposition. A number of these parties (identified in Appendix B, attached) were represented at the hearing by Counsel. The Provincial Department of Energy (the "Province"); Avon Valley Greenhouses Ltd. *et al.* ("Avon"), whose Counsel represented approximately 16 intervenors; Stora Enso Port Hawkesbury Limited and Bowater Mersey Paper Company Limited ("SEB"); Halifax Regional Municipality ("HRM"); Dalhousie Legal Aid Service ("DLAS"); Ecology Action Centre ("EAC"); Electricity Consumers Alliance of Nova Scotia ("ECANS"); Canadian Manufacturers & Exporters ("CME-NS"); GasWorks Energy Corp. ("GasWorks"); the Liberal and NDP Caucus offices; and the Municipal Electric Utilities of Nova Scotia Co-operative ("MEUNSC") all participated in the hearing. The Board also received numerous submissions from members of the public opposing NSPI's application.

[7] An initial application for a rate increase was filed by NSPI on May 28, 2004, and the Board made preliminary preparations for a public hearing in October of 2004. However, NSPI significantly altered its application following the June 11, 2004 decision of the Supreme Court of Canada to reject a long-standing tax appeal by NSPI under **s. 21** of the **Income Tax Act**. NSPI re-filed its application on June 23, 2004, requesting recovery of an additional $150 million in income tax and interest costs which it proposed to amortize

over seven years. This represented an increase over the initial 2005 test year revenue requirement of $32.7 million which, in turn, increased the proposed rates by an average of 3.8%, from the May 2004 request of 8.6% to 12.4%, with most classes subject to average increases higher than 12.4%.[3] For example, under the revised application, domestic customers would see an increase of 14.1%.

[8] Once the actual proposed increases in electricity rates were confirmed by NSPI in the June 23, 2004 revised application, the regulatory process commenced. The Board issued an Order on June 28, 2004 setting down a public hearing on NSPI's rate application commencing in mid-November, 2004. The Board established a timetable for evidence filings and information requests and responses ("IRs") that covered the period from July 15, 2004 to November 8, 2004. NSPI also conducted a number of technical conferences during this period.

[9] In its revised application, NSPI identifies its total 2005 test year revenue requirement to be $1,072.9 million,[4] and takes the view that its need for a rate increase is primarily driven by higher tax expenses. NSPI's policy panel witnesses were Mr. Chris Huskilson, President and Chief Executive Officer of Emera, and Mr. Ralph Tedesco, NSPI's Chief Operating Officer (COO). In his opening statement, Mr. Tedesco stated that:

> ... In this instance we have made an application necessitated by a tripling of our annual tax liability. This tripling of taxes represents an annual increase in our tax liability of $79 million dollars. On May 28th we filed a request to increase rates by $71 million dollars, or $8 million dollars less than the actual tax increase. Subsequently, and as a result of an unfavourable

[3] Exhibit N-6, App. O, pp. 1-3 & 20

[4] Exhibit N-6, App. O, p. 12

> tax ruling at the Supreme Court of Canada associated with **Section 21** of the **Income Tax Act**, we filed for an additional $33 million dollar increase in revenues.
>
> (Transcript, Nov. 16, 2004, pp. 27-28)

While Mr. Tedesco refers to taxes as the primary cause of the application, the increase appears to be also driven by higher fuel costs, primarily imported coal.

[10] A significant part of NSPI's evidence involves the cost of fuel, particularly imported coal. NSPI filed this data on the basis that it constitutes confidential information. The Board again imposed the precedent, established in the 2002 rate case, which provides access to this information only to those intervenors who agree to sign confidentiality undertakings.

[11] As a result, certain testimony, undertakings, exhibits and transcripts are considered confidential and are accessible only to the Board and those parties who agreed to sign confidentiality undertakings. For the most part, redacted versions of this evidence are on the public record. In addition, certain of the hearing days relating to evidence on fuel were conducted on an *in camera* basis.

[12] In its 2002 decision the Board stated that:

> While conducting *in camera* sessions is an unusual occurrence for the Board, it is not precluded by the Board's regulatory rules. Indeed the rules contemplate information being filed in confidence and also provide for other parties to request its disclosure. The Board believes that its role as a regulator responsible for protecting the public interest requires it to issue a decision that is, in all respects, accessible to the public. The Board considers that it is unacceptable to issue two versions of a decision - one public and one confidential. Therefore, although the Board has carefully considered all of the evidence filed during this proceeding, including those parts which involve confidential information, the Board has chosen, in this decision, to avoid direct reference to confidential information.
>
> (Board Decision, October 23 , 2002, p. 5)

[13] The Board continues to believe that this is the most appropriate manner in which to issue a decision in a case where a significant portion of the evidence is confidential. Accordingly, to the extent possible, this decision will not refer directly to confidential information.

[14] Just prior to November 15, 2004, the first scheduled day of the public hearing, NSPI requested that the hearing commencement be delayed until November 16, 2004. This request, which was agreed to by the Board, was as a result of significant power outages in various communities in the Province following a storm on November 13 and 14, 2004.

[15] The November outages are the subject of a separate review by this Board. On November 16, 2004, the Board received the following request from Premier John Hamm:

> The Government of Nova Scotia believes that the public interest would be served if the Utility & Review Board conducted an independent review. I therefore request that the Utility & Review Board, under the powers of the Public Utilities Act, begin a public review of the Company's state of preparedness for, and response to, last weekend's storm.
>
> This review should provide valuable insights into improvements which can be made to the overall restoration program in preparation for future outages.

[16] As part of the outage review, the Board has received a number of comments from members of the public questioning, among other things, why NSPI's request for a rate increase should be considered when the service provided by NSPI is, in the view of these customers, inadequate and unsatisfactory.

[17] While the Board recognizes the logic of this reaction, it is important to understand why this form of sanction cannot reasonably be applied to a regulated utility.

NSPI is not like an unregulated retailer. It is a virtual monopoly which operates its business on a cost-of-service basis. Providing electricity to all communities in the Province was not (and likely still is not) financially feasible for private, competitive companies. For that reason, the Province's electric service supplier is a cost-of-service monopoly. In return for undertaking and continuing the costs of electrification of the Province, the Utility is permitted, under the **Act**, to recover the reasonable and prudent costs of providing this service. Because it is a monopoly, regulation operates as a surrogate for competition. One of the regulator's tasks is to balance the need for the Utility to recover its reasonable and prudent costs with the need to ensure that ratepayers are charged fair and reasonable rates.

[18] It is in the interests of all Nova Scotians to ensure that NSPI continues to be a stable and financially sound company. This is a reality which the Board must consider when determining what, if any, rate increase is warranted.

[19] In short, rates charged to customers are based on costs incurred by the Utility in providing service. If the Board finds certain costs to be imprudent or unreasonable, it can (and has) disallowed such expenditures and reduced proposed rate increases accordingly. The Board cannot, however, make rate decisions based solely on reliability issues or current public opinion of the Utility. There are appropriate sanctions a regulator can impose should a Utility be found to have an inadequate or unreliable system. In many cases, it is likely such sanctions would involve higher expenditures, rather than reductions in costs. However, the practical reality in a regulated utility environment is that sanctions for service-related issues generally do not include a moratorium on rate increases.

[20] It should also be noted that on November 9, 2004, the Board approved a final version of the Code of Conduct. The Interim Code of Conduct was the subject of considerable discussion and input during the 2002 rate case. The Code of Conduct (set out in Appendix C) is a document which governs the manner in which NSPI conducts transactions with affiliated companies, including Emera. The principal change between the interim Code and final Code incorporates a suggestion from Counsel for Annapolis *et al.* in 2002. This revision changes the test for determining whether an affiliate transaction is acceptable. Instead of satisfying the Board that an affiliate transaction does no harm to ratepayers, NSPI is now required to show that affiliate transactions benefit ratepayers.

[21] The Board wishes to acknowledge, with appreciation, the contribution and participation of the intervenors, NSPI and the public in this proceeding. The Board has before it many thousands of pages of material to review, analyze and consider in its decision-making process. The significant work of the parties, as well as the expert witnesses appearing at the hearing, assisted the Board considerably in this process.

2.0 BACKGROUND

[22] NSPI is a vertically integrated, investor-owned, regulated public utility with a virtual monopoly on electricity service throughout the Province. In 2003, it supplied 97% of the generation, 99% of the transmission and 95% of the distribution in the Province.[5] As noted earlier, the Board regulates NSPI in the public interest on a cost-of-service basis. The **Act** gives the Board broad regulatory oversight over public utilities and provides it with the authority to discharge its regulatory responsibilities. Some of the relevant provisions are as follows:

> **Supervision of utility by Board**
>
> **18** 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 the said public utilities with the provisions of law and shall have the right to obtain from any public utility all information necessary to enable the Board to fulfil its duties. R.S., c. 380, s. 18.
>
> **Form of books and records of utility**
>
> **27** The Board may prescribe the forms of all books, accounts, papers and records required to be kept by any public utility and every public utility is required to keep and render its books, accounts, papers and records accurately and faithfully in the manner and form prescribed by the Board and to comply with all directions of the Board relating to such books, accounts, papers and records. R.S., c. 380, s. 27.
>
> **Examination and audit of accounts**
>
> **29 (1)** The Board may provide for the examination and audit of all accounts, and all items shall be allocated to the accounts in the manner prescribed by the Board.
>
> **Authority to inspect books or records of utility**
>
> **(2)** The agents, accountants or examiners employed by the Board shall have authority under the direction of the Board to inspect all and any books, accounts, papers or records and memoranda kept by any public utility. R.S., c. 380, s. 29.

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[5] Exhibit N-7, Tab 1, p. 21

Power to determine value of property of utility

30 (1) The Board may at any time, with the assistance of such engineers, accountants, valuators, counsel and others as it deems wise or advisable to employ, inquire into and determine the extent, condition and value of the whole or any portion of the property and assets of any public utility used and useful in furnishing, rendering or supplying a particular service to or for the public, as of a date to be fixed by the Board.

Duty of utility to furnish information

33 (1) Every public utility shall furnish to the Board from time to time, and as the Board may require, maps, profiles, contracts, reports of engineers and other documents, records and papers, or copies of any and all of the same in aid of any investigation and to determine the value of the property of such public utility, and every public utility shall co-operate with the Board in the work of the valuation of its property in such further particulars and to such extent as the Board may direct.

Approval of improvement over $25,000

35 No public utility shall proceed with any new construction, improvements or betterments in or extensions or additions to its property used or useful in furnishing, rendering or supplying any service which requires the expenditure of more than twenty-five thousand dollars without first securing the approval thereof by the Board. R.S., c. 380, s. 35; 2001, c. 35, s. 30.

Separate rate base for each service supplied

42 (1) The Board shall fix and determine a separate rate base for each type or kind of service furnished, rendered or supplied to the public by a public utility.

Factors considered in establishing rate base

(2) In establishing a rate base the Board shall determine the value of the physical assets of the public utility in accordance with the provisions of this Act, including in such value the actual reasonable and necessary cost of labour and supervision up to and including gang foreman, and the Board may, in its discretion, make allowances for the following matters, and such other matters as the Board deems appropriate:

(a) necessary working capital;

(b) organization expenses to the extent of such sum as the public utility may establish to the satisfaction of the Board to have been reasonably and prudently expended out of capital account in respect of organization expenses as defined by the regulations of the Board;

(c) construction overheads to the extent of such sum as the public utility may establish to the satisfaction of the Board to have been reasonably and prudently expended out of capital account in respect of engineering, superintendence, legal services, taxes and interest during construction, and like matters not included in the valuation of the physical assets;

(d) expenses of valuations to the extent of such sums as may have been expended in respect of a valuation by the Board and, with the approval of the Board, charged to capital account;

(e) costs in whole or in part of land acquired in reasonable anticipation of future requirements.

Amortization of organization and valuation expenses

(3) The Board may direct that a public utility shall make such provision as to the Board seems proper for the amortization of the sums allowed in a rate base for organization expenses and expenses of valuations, and may direct that the sums required annually for such amortization shall be charged as an operating expense.

Revision of rate base

(4) The Board may from time to time revise any rate base making due allowance for extensions and additions to, improvements or alterations in and withdrawals or retirements from, the property and assets of the public utility.

Existing rate base

(5) Until a rate base is determined by the Board for any public utility pursuant to this Section, the present rate base for such public utility as from time to time revised or accepted by the Board shall continue in effect and shall be the rate base for such public utility, provided that the Board may direct that any such public utility shall make such provision as to the Board seems proper for the amortization of the sums allowed in such rate base for organization expenses, expenses of valuations or allowances not mentioned in subsection (2) and may direct that the sums required annually for such amortization shall be charged as an operating expense. R.S., c. 380, s. 42; 1992, c. 8. s. 35.

Amount utility entitled to earn annually

45 (1) Every public utility shall be entitled to earn annually such return as the Board deems just and reasonable on the rate base as fixed and determined by the Board for each type or kind of service furnished, rendered or supplied by such public utility, provided, however, that where the Board by order requires a public utility to set aside annually any sum for or towards an amortization fund or other special reserve in respect of any service furnished, rendered or supplied, and does not in such order or in a subsequent order authorize such sum or any part thereof to be charged as an operating expense in connection with such service, such sum or part thereof shall be deducted from the amount which otherwise under this Section such public utility would be entitled to earn in respect of such service, and the net earnings from such service shall be reduced accordingly.

Earnings are in addition to expenses and allowances

(2) Such return shall be in addition to such expenses as the Board may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Board according to this Act and the rules and regulations of the Board. R.S., c. 380, s. 45.

Power to compel compliance by utility

46 The Board shall have power, after hearing and notice by order in writing, to require and compel every public utility to comply with the provisions of this Act and any municipal ordinance or regulation relating to said public utility, and to conform to the duties imposed upon it thereby by the provisions of its own charter, if any charter has or shall be granted it, provided, that nothing herein contained shall be held to relieve any public utility or its officers, agents or servants, from any punishment, fine, forfeiture or penalty for violation of any such law, ordinance, regulation or duty imposed by its charter, nor to limit, take away or restrict the jurisdiction of any court or other authority which now has or which may hereafter have power to impose any such punishment, fine, forfeiture or penalty. R.S., c. 380, s. 46.

Duty to furnish information

51 (1) Every public utility shall furnish to the Board all information required by it to carry into effect the provisions of this Act, and shall make specific answers to all specific questions submitted by the Board.

Duty to furnish safe and adequate service

52 Every public utility is required to furnish service and facilities reasonably safe and adequate and in all respects just and reasonable. R.S., c. 380, s. 52.

Approval for transfer of undertaking

62 Notwithstanding the provisions of any Act of the Legislature, no public utility shall sell, assign or transfer the whole of its undertaking or any part thereof to any person or corporation except with the approval of the Board first had and obtained. R.S., c. 380, s. 62.

Approval of schedule of rates and charges of utility

64 (1) No public utility shall charge, demand, collect or receive any compensation for any service performed by it until such public utility has first submitted for the approval of the Board a schedule of rates, tolls and charges and has obtained the approval of the Board thereof.

Filing with Board

(2) The schedule of rates, tolls and charges so approved shall be filed with the Board and shall be the only lawful rates, tolls and charges of such public utility until altered, reduced or modified as provided in this Act. R.S., c. 380, s. 64.

Equal rates and charges for similar services

67 (1) 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, and the Board may by regulation declare what shall constitute substantially similar circumstances and conditions.

Contravention prohibited

(2) The taking of tolls, rates and charges contrary to the provisions of this Section and the regulations made pursuant thereto is prohibited and declared unlawful. R.S., c. 380, s. 67.

[23] NSPI last filed an application for a general rate increase in December of 2001. The hearing was held between April and June of 2002, and the Board's decision was issued on October 23, 2002. Certain findings in the Board's 2002 decision, which are relevant to this case, can be summarized as follows:

- The Board reduced NSPI's revenue requirement by $42.4 million, which resulted in an average rate increase of 3.3%, rather than the 8.9% requested by NSPI;
- Common equity level for ratemaking purposes maintained at 35% - NSPI free to increase its actual equity ratio to 40%;
- Approved return on equity of 10.15% with earnings range of 9.90% to 10.40%;
- Reduction in estimated fuel costs - particularly imported coal - which were not sufficiently normalized for ratemaking purposes;
- Reductions in executive compensation for ratepayers' share of former President's annual salary and 50/50 share of incentive compensation for ratepayers and shareholders;
- NSPI to demonstrate that Operations, Maintenance and General (OM&G) is cost-efficient and that cost reductions affect higher levels, as well as lower levels, of the Company;
- Further review of the Interim Code of Conduct required prior to final approval;
- NSPI directed to undo the transfer of core utility functions of fuel procurement, export electricity sales and natural gas sales from Emera back to NSPI. NSPI also directed to develop in-house fuel procurement expertise, as well as develop fuel procurement policies and procedures. Fees paid by NSPI to Emera for these functions were disallowed;

- NSPI directed to "insulate" itself from Emera by using a different auditing firm than that used by Emera and by having different Chairs of the respective audit committees of each company.

[24] The Board stated in its 2002 decision that:

> In utility regulation, there are generally accepted principles which govern the rate-making exercise. The object of rate-making under a cost-of-service-based model is that, to the extent reasonably possible, rates should reflect the cost to the utility of providing electric service to each distinct customer class. In regulating NSPI, the Board is guided by these generally accepted principles as well as by case law.
>
> A widely-accepted publication written by Dr. James Bonbright entitled **Principles of Public Utility Rates,** sets out the following guidelines for determining appropriate rates:
>
> **CRITERIA OF A SOUND RATE STRUCTURE**
>
> 1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
> 2. Freedom from controversies as to proper interpretation.
> 3. Effectiveness in yielding total revenue requirements under the fair-return standard.
> 4. Revenue stability from year to year.
> 5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
> 6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
> 7. Avoidance of "undue discrimination" in rate relationships.
> 8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
>   (a) in the control of the total amounts of service supplied by the company;
>   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).
>
> (Exhibit N-92) (James Bonbright, **Principles of Public Utility Rates**, Columbia University Press, 1961, p. 291)
>
> (Board Decision, Oct. 23, 2004, pp. 14-15)

[25] The Board continues to be of the view that its decision in this case should be based on these guiding principles.

3.0 SETTLEMENT AGREEMENT

3.1 Submissions - NSPI

[26] On December 15, 2004, NSPI filed a letter, together with other documents, advising that a Settlement Agreement ("SA") had been reached between it and certain intervenors in the rate case. The terms of the settlement are set out below:

1. The company's Revenue Requirement for the 2005 test year will be increased and be set at **$1,018,000,000**.
   a. This represents a $54.9 million dollar reduction from the rate filing
      b. Average rate increase for all classes is 8.7%, except:
         i Commercial General Demand increase is 3.2% (as a result of existing high revenue cost ratio)
      c. ELIIR rate increases by 10.4% for 2005, 2-part RTP is set at the same level
      d. Revised emission standards take effect on March 1, 2005.

2. The above Revenue Requirement includes these specific components to be approved by the Board in its Order approving this settlement:
   a. OM&G of $177.0M (reflects pension discount rate change from 5.75% to 6.0% and other savings, for a total of approximately $5 million)
   b. ROE set at 9.8% within a band of 9.3% - 10.3% setting rates on an equity thickness of 37.5% and continuing the ability to grow the equity to 40%.
   c. For 2005, depreciation fixed at $122.2M (Board will permit NSPI to delay phase-in of the depreciation study by one year.)
   d. Up to $13 million of fuel expense can be deferred for collection in 2006.

3. By Order the Board will approve:
   a. Recovery of Section 21 monies (approx. $150M) by applying money currently in rates for amortization of defeasance and Glace Bay to Section 21 when those funds are no longer required for defeasance and Glace Bay. There is no change in rates with this approach. (NSPI's cash flow is reduced approximately $30 million)

b. The increase in Miscellaneous Charges (part of Other Revenue and not Electric Revenue) subject to no charge increasing by more than 50%.

c. The valuation and accounting treatment of the second LM6000 approved as submitted to the UARB.

4. Board allows for the consideration of a Fuel Adjustment Mechanism (FAM) during 2005 for the calendar year 2006, subject to the following:

   a. NSPI developing a specific FAM proposal for review by stakeholders at a Technical Conference

   b. NSPI gaining further experience in international coal markets

   c. NSPI agrees to a customer education campaign, should its request be favorably considered.

   d. NSPI recognizes UARB approval of a FAM is required

5. NSPI proposes Dalhousie Legal Aid's request for a low-income program be undertaken in a separate process including a technical conference

   a. NSPI will suggest no change in the present residential rate for the first 150 kwhrs of use. The difference to be recovered via a slightly increased 'tail block' residential rate. There is no change to the proposed overall residential rate increase.

6. New rates giving effect to this settlement will be effective January 1, 2005.

(Exhibit S-1, Terms of Recommended Settlement)

[27] NSPI also provided letters of support from a number of intervenors who agreed with the terms noted above. These include several large industrial customers such as Michelin and SEB. The Province indicated its support in a letter from the Honourable Cecil Clarke, Minister of Energy. CME-NS and EAC also advised of qualified support for the SA.

[28] The SA, if accepted, would reduce the proposed average rate increase for above-the-line customers ("ATL") (domestic, commercial, municipal and certain industrial categories) from 12.4% to 7.3%, with an increase of 8.7% for residential customers.

Below-the-line ("BTL") customers (with the exception of Generation Replacement Load Following ("GRLF") customers), whose rates are subject to annual adjustments based primarily on the fluctuating cost of fuel, would have their rate increase under the SA reduced to 10.4%. While NSPI's general rate application did not include specific projected rate increases for these customers, the SA does provide for a defined and lower rate increase for certain BTL customers and all ATL customers. As a result, the majority of NSPI's Annually Adjusted Rate ("AAR") customers are signatories to the SA.

[29] Since the domestic class of customers did not have a specific representative focused exclusively on this customer class during the rate hearing, they were not represented during the SA negotiations. As a result, following receipt of the SA filing, the Board ordered that an independent consumer advocate review the SA, solely from the perspective of domestic customers, and provide opinion evidence concerning the SA at the public hearing. On December 17, 2004, the Board engaged Nancy Brockway, of NBrockway & Assoc., a former US utility regulator and consumer advocate, to fulfill this role.

[30] In his evidence during the SA portion of the hearing, Mr. Tedesco explained how the SA was developed:

> As Mr. Huskilson and I indicated in our discussion with Commissioner Morash during cross-examination in this proceeding, we remain very much open to the opportunity to continue discussions with others to try and find a solution to the issues raised by our Rate Application. Discussions resumed with stakeholders during the hearing. Intervenors were canvassed for their input and their interest in moving forward with a settlement agreement. Some chose to participate in the settlement, others did not. Based on these conversations and meetings, in December, Nova Scotia Power filed a proposed settlement of its 2005 Rate Application with the Utility and Review Board. As with any settlement, the proposal involves substantial give and take on all -- by all participants aimed at balancing the interests of all stakeholders. Where possible, the settlement seeks to address issues that were raised by

> other intervenors, whether or not those intervenors are part of the settlement. From Nova Scotia Power's perspective, the proposed settlement represents significant concessions and will mean substantial pressures on the Company in 2005. I ask you to note that in the 12 years since privatization, the Company has had just three general rate increases totalling six percent for a pace far below the rate of inflation. As well, the Company's original application involved a commitment to keep non-pension OM&G expenses at levels less than 2002. The Company will also absorb over three million dollars in expected fuel costs. Moreover, we know that our actual pension expense will be higher than the amount in the Settlement Proposal. We have also reduced miscellaneous revenue by almost a million dollars. In addition, the settlement lowers the Company's rate of return from 10.2 percent to a mid point of 9.8. We also expect, as we have filed in modified Table 1 of Appendix A of the application, that our actual return will be 9.6 percent. The Company will also forego approximately thirty million dollars ($30,000,000) in cash flow compared to its filed application. This is mainly to accommodate the extended amortization of Section 21 tax expenses and the delayed implementation of new depreciation rates. Also regarding Section 21, this proposal is better for customers next year, is nearly equivalent to the original proposal on a net present value basis, and from a customer perspective, assuming the Company's rate of return, is actually better on a net present value basis. Finally, the settlement does not incorporate a fuel adjustment mechanism. These concessions were made in the interest of compromise and to enable a variety of concerns raised during the rate application to be addressed.
>
> (Transcript, Jan 13, 2005, pp. 3515-3518)

[31] NSPI also stressed the significance of the support of the Province for the SA and pointed out that, while Ms. Brockway recommended that the SA not be accepted, her suggested revisions would result in an average increase for customers in the domestic class of 8.2%, which is very close to the 8.7% rate proposed in the SA. NSPI also pointed out that Board Counsel's witness, Dr. John Stutz, a regulatory expert and Vice President of the Tellus Institute, who made comments on the SA in his evidence without recommending whether the Board should accept it or not, stated that:

> **Q. HOW DOES THE SETTLEMENT AFFECT THE PROPOSED INCREASE?**
>
> A. The settlement reduces the rate-related increase in NSPI's required revenues from $104.4 million to $49.5 million. This is a reduction of $54.9 million, or roughly 53 percent. As shown in the spreadsheet accompanying the Settlement, this reduces the average increase in revenues for the above-the-line rates from 12.4 to 7.3 percent. Increases for two of the below-the-line rates—ELIIR and 2-Part RTP—are also reduced. To achieve these reductions the Settlement relies heavily on deferrals, including a 16-year amortization of Section 21 tax costs beginning in 2006.
>
> **Q. ARE THERE BENEFITS ASSOCIATED WITH THE USE OF DEFERRALS TO LESSEN THE INCREASE?**

A. Yes. Absent the Settlement, the Board might, for example, decide to set the Company's return on common equity (ROE) below 9.8 percent or disallow $30 million or more of NSPI's test year fuel costs of $377.1 million. Such actions could have substantial, adverse impacts on the Company's financial health. The Settlement will not make things easy for NSPI in 2005. However, compared to the alternatives mentioned above, its acceptance will likely allow the Company to devote more of its energy to longer-term issues such as its fuel procurement strategy and the below-the-line rates.

(Exhibit S-3, pp. 2-3)

[32] In response to considerable criticism from intervenors who oppose the SA, NSPI, in its rebuttal submission, defended both the SA and the process by which it was reached. It stated that:

... as the Company has indicated, other parties were again approached to try and involve them in the consensus. It was not take-it-or-leave it. The Company made a determined effort to include others, including those who now still oppose the settlement.

A reasonable view of the process that unfolded is that the intervenors wanted any and every opportunity to challenge and lower the Company's revenue requirement, and the rate increases that flow from that revenue requirement. The settlement proposal attempts to meet the interests of the broader range of customers by using a combination of revenue reductions, deferrals and extended amortization to lower the revenue requirement by $54.9 million.

The settlement attempts to balance the interests of each class of customers by arriving at an average increase of 7.3 percent to above the line customers, and a 10.4 percent increase to the below the line customers on the ELIIR rate. This is a classic interest-based approach to a resolving issues that affect many stakeholders. The opposite approach involves holding fast to positions that other parties in the process, for whatever reasons, are unable to support. ...

Contrary to the arguments put forward by some, if the Board rejects the settlement proposal on the narrow issue of the process involved, it would just as easily rewarding behaviour of those who choose not to participate. This could effectively create a veto over constructive attempts to build consensus.

Certain intervenors, one could conclude, are more interested in a punitive disallowance of certain utility costs than in the broader objective of working together to accomplish a reduction in the revenue requirement in the interests of all customers without causing undue harm to the utility.

(NSPI, Reply to Closing Arguments - SA, pp. 4-5)

3.2 Submissions - Intervenors

[33] Those intervenors who do not support the SA oppose it on several grounds. These can be fairly summarized, in part, as follows:

- The SA is disproportionately beneficial to BTL customers;
- The SA negotiating process was not adequately inclusive or timely and, as such, was unfair;
- NSPI's expenses are primarily deferred, not reduced;
- NSPI escapes potential sanctions relating to issues such as fuel procurement prudence, while the fuel deferral it seeks would actually increase the fuel costs to be recovered.

[34] Avon, MEUNSC, ECANS, DLAS, HRM and Howard Epstein, MLA, on behalf of the NDP, all cross-examined witnesses and filed written submissions opposing the SA. Since certain of the parties named in Avon's original list of intervenors did agree to the SA, Counsel for Avon, Robert Grant, Q.C., and Nancy Rubin, represented fewer intervenors during the SA portion of the hearing. Avon, in its filing, submits that the Board's legal obligation in assessing the SA is:

> Acceptance of a settlement can only be undertaken judicially in our submission by careful consideration of what the evidence and submissions before the Board warrant and consideration of whether it is in the public interest to make an order reflecting the proposed settlement.
>
> (Avon, Closing Submission - SA, p. 10)

[35] Ms. Brockway, in her evidence, recommends that the Board reject the SA. In Ms. Brockway's view, revisions to the SA to address her concerns would result in an average increase in rates for domestic customers of 8.2%. She summarized her recommendation as follows:

> The settlement has three major flaws from the perspective of domestic customers:
>
> > First, it overstates the revenue requirements of the Company, based on the evidence in this docket, particularly by overstating the Company's required return, the Company's fuel costs, and certain OM&G costs.
> >
> > Second, it masks the total cost of the settlement to consumers by deferring cost recovery of the fuel costs not sought in the filing, and by deferring and stretching out cost recovery of Section 21 expenses for an unreasonable period.
> >
> > Third, to the extent it is determined accurately to represent the Company's revenue requirements, it does not give the domestic customers a fair allocation of the increase in revenues allowed to the Company.
>
> Also, the proposed settlement would allow Miscellaneous Charges to increase by as much as 50%, which will put an unreasonable burden on domestic customers, particularly low-income domestic customers. In addition, the proposed settlement would leave issues of affiliate transactions and conflict of interest unaddressed.
>
> (Exhibit S-4, p. 3)

[36] As noted earlier, Dr. Stutz, in his evidence, commented on aspects of the SA without recommending acceptance or rejection of the SA by the Board. He noted that under the SA, deferrals, rather than actual reductions of costs, are used to reduce the rates originally sought. He acknowledged that acceptance of the SA will not "make things easy" for the Company in 2005 and pointed out that ongoing effort is required to develop "... a more workable set of below-the-line rates ..."[6]

3.3 Findings

[37] The Board has concluded that acceptance of the SA is not warranted in this case. The Board wishes to make it clear that its conclusion is based on certain

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[6] Exhibit S-3, p. 7

unacceptable terms in the SA (the reasons for which are detailed below) and is not as the result of a negative view on the Board's part regarding SA's in general.

[38] The Board does not object, in principle, to SAs. Obviously, unanimous SAs are more persuasive than contested SAs but, potentially, either could be acceptable to the regulator. The Board understands and appreciates the considerable efforts expended by NSPI and the intervenors involved in the negotiations, including the Province.

[39] The parties arguing against the SA appeared to be opposed, not only to certain of its terms, but also to the process by which it was negotiated—particularly the timing and extent of their respective inclusion in the process. For example, ECANS and DLAS, in their written submissions on the SA, outlined their views as to the inadequate opportunity NSPI provided for stakeholder input. The Board believes that, in future, should a similar effort be undertaken by NSPI, the factors which clearly offended a number of parties in this case ought to be carefully assessed and avoided.

[40] In the Board's view, Avon, in its closing submission on this issue, has succinctly described what the Board is obliged to do when considering the SA. Essentially, the Board must be satisfied that the evidence heard during the rate hearing supports approving the SA. On a number of occasions during the SA hearing, questions were posed to NSPI regarding whether flexibility existed for the Board to change or amend certain elements of the SA without voiding or defeating the purpose of the SA. With minimal exception, Mr. Tedesco indicated that the terms set out in the SA are integral and

that "... the settlement should be treated as a whole."[7] Accordingly, the Board concludes that changes, which it believes are necessary, cannot be made without essentially voiding the SA 'as a whole'.

[41] Since the Board is duty bound to accept the SA only if it is satisfied that the SA is warranted by the evidence and, since it does not have the flexibility to adequately address issues of concern in the SA, the Board is unable to accept it. From the Board's perspective, there is one principal reason why it cannot accept the SA and one other factor which also weighs against acceptance.

[42] The principal reason for rejection of the SA concerns fuel. During the course of the rate hearing, most of the fuel experts were of the view that NSPI's fuel procurement practices are inadequate and imprudent and, as a result, NSPI and its ratepayers are faced with higher than necessary fuel costs. Ms. Emily Medine, a principal in the firm of Energy Ventures Analysis, and NSPI's able and credible fuel expert could not, in the Board's opinion, provide adequate evidence to the contrary. The Board will detail its findings on this subject in the fuel section of this decision. However, if the SA were to be accepted by the Board, the significantly higher cost of fuel projected by NSPI would be passed on to ratepayers, either in 2005 or, in later years, by deferral. The evidence heard by the Board during the rate hearing simply does not warrant this result.

[43] NSPI correctly notes that the result of the SA—an 8.7% increase for most ATL customers (including domestic), is very similar to the 8.2% which Ms. Brockway

[7] Transcript, January 13, 2005, pp. 3685-3686

indicated would reflect a more acceptable SA for domestic customers. However, a similar mathematical end result does not address the important principles of prudency and fairness. If the Board does not believe that fuel procurement was adequately managed and finds that certain coal costs should be disallowed as imprudent, how can it accept an SA which passes these costs on to ratepayers? This would not be fair or reasonable or in the public interest and, as a result, the Board cannot accept the SA.

[44] The second factor which weighs against approval of the SA is the inclusion of term 3(c) in the agreement. This refers to the most recent LM6000 combustion turbine unit installed at NSPI's Tufts Cove generating station. The installation of this additional LM6000 unit at Tufts Cove was approved by the Board on an "emergency" basis following a request from NSPI in March of 2004. The LM6000 had previously been purchased by Emera and it was placed in storage in Port Hawkesbury in October of 2001.[8] The LM6000 remained unused in storage until it was installed at Tufts Cove in late 2004. NSPI's March, 2004 request to immediately install the LM6000 warned of potential outages which could result in early 2005 from inadequate generation in high demand situations, combined with severe weather conditions, if the Board did not approve the request. The Board, noting that Emera was transferring the LM6000 to NSPI, and that NSPI had been working on generating capacity addition issues with a number of stakeholders in a process which could be undermined by the LM6000 request, gave only conditional approval for the unit's installation.

[8]NSPI Response to Board IR-1, LM6000 request process

[45] The conditions imposed by the Board were that the transfer cost between Emera and NSPI for the LM6000 be reviewed by an independent consultant and that capacity addition stakeholders would have an opportunity to review and comment on the independent expert's report. At the time of the SA, this process was underway. Stone and Webster Inc. and PricewaterhouseCoopers (PwC) were engaged by the Board to review the LM6000 transfer cost. Their report was received and circulated to stakeholders. It recommends a somewhat lower transfer price for the LM6000 than that proposed by NSPI.

[46] The SA, if approved, would void this process and would permit NSPI to pay its proposed higher cost to Emera for the LM6000. The higher cost for this unit would ultimately be passed on to ratepayers. It is unlikely, in the Board's view, that any party in this proceeding, other than NSPI, benefits from this term in the SA. The Board is not prepared to accept it and, as a result, the inclusion of this term in the SA weighs against its approval. The Board comments further on this matter later in this decision.

4.0 FUEL ISSUES

4.1 Procurement Strategy and Prudency

4.1.1 Submissions - NSPI

[47] The cost of fuel and purchased power is the single largest cost borne by NSPI. In its June 23, 2004 revised application filing, NSPI confirmed this cost to be $377.1 million for the 2005 test year. This is an increase of $33.2 million over the 2002 cost which was used as a basis for the last rate adjustment, and is approximately $94 million more than NSPI's forecasted 2004 cost for fuel and purchased power.[9]

[48] According to NSPI, these cost increases are based on five factors which are summarized below:

- a 57% increase in the cost of low sulphur coal
- reduction in profits from gas resales due to contract changes
- 2005 SO_2 emissions reduction requires the purchase of a higher amount of more expensive low sulphur import coal
- increase in cost of heavy fuel oil
- increase in fuel transportation costs

(Redacted Summary of Exhibits N-1 and N-4, p. 23)

[49] NSPI generates electricity using several varieties of fuel. These include heavy and light fuel oil, natural gas, domestic coal, petroleum coke and imported coal. For the purposes of this decision, the focus is primarily based on NSPI's structure and practices used in contracting for the supply of imported coal.

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[9]Exhibit N-1, pp. 22-23

[50] It is the information and evidence relating to fuel procurement and costs which constitutes the confidential data referred to earlier in this decision. The witnesses who testified on this matter at the hearing did so during *in camera* sessions. While the Board has considered this confidential data in making its decision, the description of the evidence heard and the explanations for Board findings which are set out in this section of the decision generally are from redacted versions of evidence filed and summaries of confidential material.

[51] NSPI described its fuel strategy as follows:

> In general, NSPI's fuel strategy is to stay close to the market and leverage fuel diversity. Staying close to the market means that the Company's contracts provide for the delivered cost of fuels over terms that extend up to 24 months. During this 24-month window, NSPI locks in contracts for varying amounts of the Company's fuel requirement based on market opportunities. The Company reacts to short-term market changes to contract the lowest cost fuel over time, and pays no premiums (to compensate the seller for the extended term) for short-term contracts. NSPI's strategy provides a high degree of flexibility in optimizing the mix of fuels at any particular facility and in any given year...
>
> On the advice of Emily Medine, the Company's expert fuel witness (see Section 3.6), NSPI believes that it should increase the amount of coal that it purchases under contract if such coal can be obtained on attractive terms.
>
> Given the level of volatility in the coal market over the last few years, NSPI believes it could benefit from additional term commitments subject to market conditions. NSPI will enter into term contracts as part of its supply portfolio where the premium for the term is reasonable.
>
> (Exhibit N-1, pp. 31-32)

[52] NSPI also described its attempts, between late 2002 and 2004, to obtain multi-year imported coal supply contracts. These attempts were unsuccessful as, in NSPI's view, the limited number of the responses which it did receive to its solicitations had prices which were too high to warrant entering into multi-year contracts. The Company also described its practice of 'hedging', a form of insuring against swings in costs, and the

risks it faces in terms of fuel costs and foreign exchange rates, principally in US dollars.[10] NSPI advises that its world coal market expertise has increased since the Board's 2002 decision and points out that much of its purchases of petroleum coke is on the basis of multi-year contracts.

[53] In February of 2003, NSPI engaged the services of Emily Medine, a fuel procurement expert who gave evidence for a group of intervenors (Annapolis *et al.*) in the 2002 rate hearing. Ms. Medine's engagement with NSPI was in response to the direction of the Board in its 2002 rate decision that NSPI improve its fuel procurement expertise and processes. Ms. Medine's September, 2003 report to NSPI outlined suggested improvements to NSPI's fuel procurement policies and procedures, including the goal of developing a mixed portfolio of short, mid-term and long-term supply contracts.

[54] Along with recommending approval of a FAM (which will be discussed later in this decision), Ms. Medine's evidence in the current hearing outlined progress made by NSPI since 2002 in improving its fuel procurement strategy; its compliance with the Board's 2002 directives for changes in this area; and the reasonableness of its fuel cost estimates for 2005.

[55] In Exhibit N-42, NSPI states that:

> Contrary to the evidence from certain witnesses, NSPI has been active in soliciting tenders for multi-year term contracts for all the components that make up the fuel expense. NSPI has successfully awarded multi-year contracts, ranging from 30 months to ten years, for local coal; pet coke; natural gas; ocean freight; coal handling and local transport storage at Sydney port; coal handling/storage at Aulds Cove, natural gas transport; and a limestone supply contract for Point Aconi.

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[10] Exhibit N-1, pp. 32-36

> NSPI has gone to tender for multi-year supply of coal five times since the spring of 2002, and on each occasion (when quotes were submitted) the prices tendered exceeded market prediction to the degree that NSPI did not place an order. Based on the information available to NSPI at the time of evaluation there was no justification to award those multi-year volumes. The award would have resulted in higher costs in 2003 and 2004. (See Table 3.1 for summary of multi-year coal bids.)
>
> NSPI did not receive any offer for multi-year contracts with three-to-five year terms with a 20 percent volume flexibility. Mr. Spangenberg recommends these contracts should make up 60 percent of NSPI's portfolio. The multi-year offers received by NSPI from the spring of 2002 to present carried significant premium to market, which viewed in the context of information available at the time, NSPI chose not to accept. Moreover, long-term contracts typically include pricing that is linked to a specific market index, and therefore cannot be hedged.
>
> (Exhibit N-42, p. 64)

[56] Essentially, the Company submits that its fuel procurement strategy is reasonable and appropriate and it refutes the suggestions of other fuel experts who suggest that NSPI's fuel procurement is imprudent. NSPI noted that similar allegations were made in the 2002 rate hearing and points out that, in its 2002 rate decision, the Board did not make any finding of imprudence. The relevant excerpt of the Board's decision states:

> After evaluating all the evidence concerning NSPI's coal procurement strategy, the Board finds that NSPI's actions do not go so far as to constitute imprudence.
>
> Although NSPI had contracted on the international market for some part of its coal requirement in the late 1990's, the bulk of its coal was supplied by CBDC pursuant to a long-term supply agreement dating back to 1978. NSPI's coal supply situation changed drastically between 1999 and 2001 with the decline in production at CBDC's mines followed by the announced closure of all of CBDC's coal mines in the spring of 2001. Accordingly, NSPI has not had a lengthy history of involvement in the international coal markets. The Board surmises that its learning curve has been a steep one. While not imprudent, the Board considers that NSPI's coal procurement strategy has been lacking in sophistication. However, the Board is not prepared to find that NSPI's strategy of buying coal pursuant to short-term contracts on the international markets was fundamentally flawed. The Board agrees with Ms. Medine, however, that stringent procedures should be in place to govern coal procurement (i.e., practices and procedures setting out approved methods for issuing bids for coal supply) as coal acquisition accounts for a huge portion of NSPI's total expenses. The records show considerable sloppiness on NSPI's part in terms of its purchasing practices, including the interchangeable and confusing use of Emera and NSPI as the contracting party for coal. ...

> Notwithstanding that the Board does not consider that the evidence supports a finding of imprudence on the part of NSPI, the Board does believe that NSPI's practices in this area are sufficiently lax so as to undermine NSPI's ability to ensure, and demonstrate to the Board, that coal was obtained at the lowest possible price. NSPI's argument that it had an "evolving" relationship with Emera Energy does not justify the confusing document trail in terms of who was actually contracting for coal. In the Board's view, there is too much at stake and, consequently, too significant a potential impact on ratepayers, to accept anything less than the best possible business practice.
>
> (Board Decision, P-875, October 23, 2002, pp. 27-28)

[57] NSPI has cited decisions of regulatory bodies in Canada and the U.S. regarding prudency standards. It suggests, in its rebuttal evidence and in its closing submission, that the experts who allege imprudency on NSPI's part have not followed the appropriate legal standards for determining what constitutes imprudency in a regulatory environment. NSPI also points to the evidence of Dr. Stutz who, while recommending a reduction of $30 million in fuel costs (which NSPI also argues against), based his justification for the reduction on the principle of fuel cost "normalization" rather than imprudence.

[58] NSPI also emphasizes that its "evolving" fuel procurement strategy was the subject of reports and information filed with the Board in 2003 and 2004 and notes that, until evidence was filed by expert witnesses with Liberty Consulting Group ("Liberty"), Board Counsel's witnesses, in October of 2004, no objection had been raised by the Board regarding NSPI's actions during this period. NSPI vigorously disputes the opinions of Liberty and the intervenors' experts which indicate that, if NSPI had properly developed a mixed fuel procurement strategy, providing for a variety of coal supply contracts, including long-term contracts, and used these tools in late 2002 and part of 2003, it would not face as significant an impact as it now does due to the high cost of coal in 2005. NSPI suggests

that it has made valid efforts to acquire longer term coal supply prices, but limited availability of such contracts and high prices associated with the few offers received, has, since late 2002, effectively hindered NSPI's ability to enter into longer term imported coal contracts.

[59] Ms. Medine gave evidence during the *in camera* portion of the hearing regarding her views of NSPI's fuel procurement. She confirmed to Robert Grant, Avon's Counsel, that she advised NSPI to alter its tendering process to ensure coal suppliers would perceive NSPI's long-term coal contract solicitation as serious. She also confirmed that her firm was first asked to advise NSPI regarding specific procurement tenders in May of 2004.

[60] Ms. Medine acknowledged under cross-examination by Stephen McGrath, Counsel for the Province, that in her 2002 rate case evidence she was of the view that NSPI's coal bidders list used for solicitation was inadequate and that this advice was repeated to NSPI in her report to the Company in the latter part of 2003.

[61] James Taylor, NSPI's General Manager of Power Production, confirmed to Mr. McGrath that NSPI plans to solicit supply quarterly began in 2004 and that solicitation in 2003 occurred on two occasions – once in January and again in September.

[62] Ms. Medine defended NSPI for not having long-term contracts by indicating that for much of the period in question, coal prices were moving up and, when prices are rising, it is not advisable to lock in to long-term, high-volume contracts. She acknowledged, under questioning from Board Counsel, that this increase in price began in late 2003.

[63] Ms. Medine also acknowledged, in response to questions from Board Counsel, that NSPI's revised fuel procurement and policies manual, which is dated July, 2004, appears to continue NSPI's trend to 'stay close' to the fuel market and to prefer, in many cases, contracts no longer than 24 months. While both she and Mr. Taylor described NSPI's evolving practice in this regard, they acknowledged that, currently, NSPI does not have any long-term contracts for imported coal.

4.1.2 Submissions - Intervenors

[64] SEB and Avon presented evidence from fuel experts regarding NSPI's fuel procurement practices. Liberty also gave expert evidence on this matter.

[65] Colin V. Gubbins of the McCloskey Group, Richard Marston of Marston & Marston Inc. and Sharon Hennings of Brubaker and Associates Inc. all gave evidence on behalf of SEB with respect to fuel. Both Mr. Gubbins and Mr. Marston provided their views with respect to world coal markets and NSPI's fuel procurement practices in pre-filed direct evidence and in their testimony at the hearing. Both experts take a similar view of NSPI's procurement strategy. They do not believe it is appropriate. In their opinion, NSPI has not, since 2002, adequately pursued a balanced portfolio of short, mid-term and long-term coal supply contracts and, consequently, customers are not adequately protected against price volatility. They were critical of NSPI's solicitation of the market between 2002 and 2004 for long-term contracts. They noted that coal prices had reached low levels in late 2002 and that Ms. Medine's evidence in the 2002 hearing, which indicated that NSPI should

pursue a balanced portfolio of short, mid and long-term contracts, was correct. In their view, NSPI did not act quickly or effectively enough to follow this advice.

[66] Mr. Gubbins and Mr. Marston generally agree that NSPI had a window of opportunity in late 2002 and early 2003 to lock in reasonably priced, long-term coal supply contracts. They indicated that NSPI overlooked this opportunity and, instead, focused on shorter term contracts. As a result, NSPI and its ratepayers are exposed to a sharp increase in coal prices and, had NSPI acted prudently, this price increase could have been reduced. Mr. Marston, in Exhibit N-71, indicated that NSPI relies primarily on market timing in solid fuel purchases, rather than clear guidelines or price objectives. His opinion is that the solid imported fuel costs projected by NSPI for 2005 are "... based on an unreasonable and imprudent fuel procurement strategy and are unreasonably high because of NSPI's over-exposure to short-term and spot contracts."[11] Mr. Gubbins advises that, despite the reference to 24 months as the preferred maximum length of fuel supply contracts noted in NSPI's new manual, long-term contracts are generally understood in the industry to be between three and five years in length.

[67] Dr. Manfred Raschke, of International Strategic Information Services, gave fuel evidence on behalf of Avon. He is also of the view that a balanced portfolio of short, mid-term and long-term coal supply contracts is necessary to avoid high risk exposure to coal price volatility and is essential for a prudent fuel procurement strategy. He indicated that, in his opinion, NSPI does not have a balanced portfolio for coal supply and, as a

[11]Exhibit N-71, pp. 2-4

result, NSPI and its customers are vulnerable to spot markets and price volatility. Dr. Raschke also pointed out that had NSPI moved quickly to adopt a balanced portfolio in late 2002 and early 2003 (which was Ms. Medine's advice during the 2002 rate case) it could have reduced the impact of the high 2005 coal costs it now faces.

[68] Liberty expert witnesses were John Antonuk, Donald T. Spangenberg, Jr., Dennis Kalbarczyk and John B. Adger, Jr. They took a similar view with respect to NSPI's fuel procurement strategy. Mr. Spangenberg indicated that his review of NSPI centred on fuel management, particularly coal. He testified that, in his opinion, NSPI did not use a balanced portfolio approach to secure coal supplies and that NSPI's fuel procurement procedures, as well as the structure of its organization and internal expertise relating to this issue, are inadequate.

[69] Mr. Spangenberg explained his concerns regarding NSPI's fuel procurement relating to the organization and structure of the decision-making process. He said that, since most of NSPI's decisions on fuel supply are made by a committee rather than by specialized individuals, effectiveness and accountability on fuel supply decisions is not adequate. He pointed out that NSPI's process involves decision-making by a 'fuel strategy table', which includes Mr. Huskilson, Mr. Tedesco, Todd Sattler, Vice-President of Emera Energy Services, and several other individuals. Mr. Spangenberg described a preferred, and in his experience more common, fuel decision-making process in a utility as one which sets out decision-making autonomy which graduates up the chain of command. Each level is authorized to enter into contracts within a certain cost range, although decisions with

major cost implications may be overseen by senior executives. According to Mr. Spangenberg, this improves efficiency and accountability in the utility.

[70] In the view of Mr. Spangenberg, as a result of NSPI's inadequate coal purchasing practices, it now cannot demonstrate that the coal it is purchasing will produce electricity at the lowest possible cost. According to Mr. Spangenberg, NSPI has been imprudent and its projected fuel costs should be reduced by $28.9 million. Other fuel experts suggested a similar reduction.

[71] Mr. Spangenberg's observations concerning NSPI's fuel procurement practices are set out in the redacted version of his evidence as follows:

- Because fuel planning has been weak at NSPI, the overall fuel strategy is weak and not well defined.
- NSPI has not adopted an appropriate portfolio approach to coal procurement, and continues essentially to rely upon the spot market for a vast share of its coal supplies.
- NSPI has not included a sufficient number and variety of long-term coal contracts in its coal supply portfolio.
- NSPI's coal solicitations have not conveyed an image of professionalism to the coal supply market.
- NSPI has not prepared, or included sufficient production quality model runs in its long-term coal supply analyses in order to properly evaluate issues such as fuel switching costs to comply with the lower SO_2 cap.
- NSPI does not track transportation costs separately as necessary to consider future transportation costs in making and executing fuel management plans.
- NSPI's Fuel Procurement Policies and Procedures are weak and need significant improvement.
- NSPI's policies and procedures for fuel hedging are weak and need significant improvement.
- NSPI is not able to demonstrate that it procures fuels that will produce the lowest possible cost of electrical energy delivered to the bus-bar.
- NSPI's organization is not structured nor staffed appropriately to provide for effective fuel management.
- NSPI's organizational structure raises several areas of concern in the area of conflicts of interest related to affiliate relations.

- NSPI has not established the proper performance baseline in the area of fuel management necessary to justify introduction of a Fuel Adjustment Mechanism.
- NSPI demonstrated imprudence by missing the opportunity to save $28,935,500 on coal supplies for the year 2005.

(Exhibit N-136, pp. 5-6)

Mr. Spangenberg's recommendations are:

1. NSPI should immediately conduct an overall re-evaluation of its generating system to determine the optimum way of meeting new requirements for control of SO_2 emissions, as well as emissions of other pollutants of concern, from its generating plants. Such re-evaluation should incorporate a long-term view, not just the next several years. The recommended study should consider not only all fuel supply options, but also integration of fuel supply options with capital expenditures for alteration, modification or expansion of its generating units in order to achieve the lowest possible costs for generation of power, consistent with other issues of reliability, environmental concerns and legal issues.
2. Consistent with item #1 above, NSPI should immediately revise its fuel portfolio strategy to incorporate a balance of both short-term (or spot) and long-term fuel contracts with terms ranging from one up to seven years, with expiration dates not all occurring at the same time.
3. NSPI should adopt a consistent policy of annual solicitations for long-term coal supply that are accompanied by production quality model runs for at least seven years into the future in order to determine actual fuel requirements. Such model runs should also provide the base for evaluation of proposals received from coal suppliers in order to conduct analysis of variances, such as fuel switching costs to comply with the lower SO_2 emission requirements.
4. NSPI should revise its coal solicitation process to make it an aggressive one that conveys the image of a utility operating from a position of professionalism and strength. RFP language must be clear and correct, and RFP's must be very clear about the specific fuel supply needs of the future, in terms of tonnes of coal required for each year in the future up to a maximum of seven years. Do not leave tonnages and years of supply at the discretion of fuel suppliers. NSPI must demonstrate it is a professional and serious fuel buyer that knows what it wants, and when it wants it.
5. NSPI should revise the Fuel Procurement Policies and Procedures Manual to incorporate the suggested improvements as listed in Exhibit DTS-3.
6. NSPI should develop a more comprehensive set of fuel hedging policies and procedures, along the lines as suggested in this testimony.
7. NSPI should commit to either procurement, or internal development of a comprehensive fuel procurement model that permits evaluation of fuel supply options, and procurement decision-making on the basis of procuring that mix of fuels that will result in producing the lowest possible cost of electrical energy delivered to the bus-bar.
8. NSPI should resolve the seven organizational weaknesses described in this testimony in a manner that is satisfactory to the Nova Scotia Utility and Review Board.

> 9. NSPI should resolve all of the above eight recommendations of this testimony in a manner that is satisfactory to the Nova Scotia Utility and Review Board before reconsidering resubmission of any application to institute a Fuel Adjustment Mechanism.
>
> (Exhibit N-136, pp. 6-8)

[72] Dr. Stutz recommends a reduction in NSPI's fuel costs on the basis of what he refers to as "normalization" as opposed to imprudency. In Dr. Stutz's opinion, it is inappropriate to use abnormally high fuel costs for ratemaking purposes as NSPI has done. Dr. Stutz, in his direct evidence, recommended a reduction in NSPI's 2005 proposed fuel costs of $58.9 million. In his surrebuttal evidence he revised this amount to $29.4 million, noting that:

> Q. RETURNING TO AN EARLIER POINT, HOW MUCH SHOULD NSPI'S TEST YEAR FUEL COSTS BE NORMALIZED?
>
> A. How much to normalize, that is how close to the historic mean to set Total Fuel Cost per MWH, is a matter of judgment. In a period of increased volatility in fuel prices, without a FAM the Company does face increased risk. To address this issue, I am raising my recommendation from $24.94, the historic mean, to $27.25, half-way to the Company's figure of $29.56. This will increase NSPI's required revenues by about $29.5 million.
>
> Q. PLEASE EXPLAIN HOW YOUR RECOMMENDATION ADDRESSES RISK.
>
> A. In the 2002 General Rate Proceeding, NSPI initially requested a Total Fuel Cost of $30.98 per MWH. On compliance with the Board's decision, the figure was $28.64, a reduction of $2.34. Here, the difference between the Company's proposed $29.56 and my recommended $27.25 is $2.31. Normalization by roughly the amount proposed here allowed NSPI to earn a return on equity of 10.15 percent in 2003, 10.47 percent in 2003, and an expected 10.40 percent in 2004. Thus, based on NSPI's experience since 2001, my revised recommendation addresses risk without establishing a FAM.
>
> The purpose of my revised recommendation is to set the total Fuel Cost per MWH included in required revenues at a representative level. After considering the issues addressed by the fuel experts - prudence in coal purchasing, likely revenues from gas sales, etc - the Board may find it appropriate to select a higher or lower figure than the $27.25 I have proposed. My key point is that, for now, in spite of NSPI's increased volatility in fuel costs, the appropriate course of action is to set fuel costs at a representative level and not establish a FAM.
>
> (Exhibit N-231, pp. 7-8)

[73] In his evidence at the SA portion of the hearing, Dr. Stutz stated that:

> ... My recommendations -- I think the only ones I really want to touch on is the fuel-related costs. I said initially that they should be set at the historic average of total fuel cost, that is twenty-four ninety-four per megawatt hour. In my surrebuttal I raise that to twenty-seven twenty-five per megawatt hour. This reflects my concern that the company does bear substantial risk and my desire on average to balance setting representative costs with ensuring that in the test year the company faces a reasonable situation. This is where I think the balance sits, but I would again acknowledge that that's a matter of judgment.
>
> (Transcript, Dec. 3, 2004, p. 3394)

[74] In its closing submission, Avon points out the similarities in the fuel experts' views on NSPI's procurement practices:

> If there is any consensus among the experts it is that NSPI must adopt a fuel procurement strategy with a portfolio of different coal contracts for imported coal. ...
>
> NSPI can no longer claim that it is inexperienced in the international coal market as it did in 2002. The consensus of the experts with respect to what constitutes prudent fuel management and an appropriate coal procurement strategy is striking. ...
>
> NSPI has defended its failure to enter into longer term contracts essentially on the basis that it was not prepared to do so until the market had turned up again in late 2003. At that time, it would not have been appropriate to lock in long-term. NSPI has pleaded that it took time to address the recommendations of the Board arising from the 2002 rate case.
>
> The surrebuttal of the Liberty consultants address this argument succinctly noting that:
>
>> It would defy simple logic to contend that the fact that it takes time to correct a failing that should not have existed in the first place (in a prudently managed operation) excuses the imprudence of allowing the failure to have come about. The most one could say is that the timely correction of imprudent behaviour avoids a compounding of a management failing; it certainly does not excuse it.
>
> With respect, while NSPI's efforts may be steps in the right direction, surely, given the clear direction imparted to NSPI in the last rate case and all the information respecting the cyclicality in the market, it was incumbent upon NSPI to take immediate and focused steps to accomplish a balanced portfolio. The opportunities were available in 2002. The opportunities were available in 2003. As Ms. Medine noted on questioning by Mr. Outhouse, "It was a bit of a buyer's market probably beginning in 2002 – mid 2002 through mid 2003....
>
> Consistent with the views of Dr. Raschke, Mr. Spangenberg, Mr. Marston and Mr. Gubbins, these intervenors submit that a case for imprudence has been made out such that this Board ought to disallow approximately $30 million of fuel costs from the 2005 revenue requirement.
>
> (Avon, Closing Submission, pp. 20-26)

[75] The similar findings of fuel experts were also noted by ECANS which stated that:

> NSPI's initial filing included a total cost of fuel at $377.1 million and subsequent information showed a revised fuel cost at $393.7 million – a commanding 38% of NSPI's total revenue requirement. According to NSPI and its experts, much of this increase is due to the resurgence or development of the Chinese economy. China's demand for energy-related products is placing stress on the entire global energy industry, particularly low sulphur coal and associated ocean transportation. It is clear to all parties that **fuel and fuel procurement are THE fundamental issues in this rate case**. The simple magnitude of the number dictates the degree of examination and evaluation that must be contributed by the utility, the regulator, the shareholders and most importantly the ratepayers.
>
> In view of the enormity of the issue, it is understandable why so much of the hearing was dedicated to examining NSPI's fuel-related issues. In fact, this rate case contained more witnesses than the 2002 hearing. In this case they included:
>
> - Tim Simard and Emily Medine (for NSPI)
> - Colin Gubbins, Sharon Hennings and Richard Marston (for StoraEnso and Bowater)
> - Donald Spangenberg, John Antonuk, John Adger, and Dennis Kalbarczyk (for Board staff)
> - Manfred Raschke (for Avon valley et al)
>
> All would agree this was a formidable array of coal-market talent who very much expanded our understanding of what is happening on the international coal scene. Of course, witnesses for the intervenors and for Board staff held a common and not-so-complimentary view of how well NSPI performed in handling its fuel procurement. In fact, their independent evaluations arrived at the same conclusion in terms of fuel costs that should be denied by the Board. Since this part of the hearing was conducted via in-camera sessions, we are unsure how much of those proceedings can be referred to in this submission. However, in summary form, the intervenor witnesses agreed to the following:

Average Amount of Denied Costs	$30 million

> Although individual assessments differed slightly on how much of NSPI claimed fuel costs should be denied, they were unanimous in their overall assessment of NSPI's inability to competently procure fuel for the company; stressing that ratepayers should not be held responsible for mistakes made by the utility.
>
> (ECANS, Final Brief, pp. 5-6, emphasis in original)

[76] ECANS recommends that:

> NSPI's approved fuel budget be reduced by $20 million
>
> NSPI be directed to establish, support and develop a strong fuel procurement department
>
> (ECANS, Final Brief, p. 11)

[77] MEUNSC endorses Dr. Stutz's opinion on fuel costs:

> The primary concern has been placed in the proper context by Dr. Stutz;
>
> > "as in 2001, NSPI asks The Board to approve rates which embody a Total Fuel Cost per MWH which is higher than any historic value, and far above the historic average" (emphasis added)
> >
> > Evidence filed by John Stutz, October 15, 2004 page 28 lines 9-13
>
> He points out that if the 2001 estimates had been approved NSP would have over recovered by upwards of **$249 million**.
>
> In answering the question of whether or not the high costs proposed for this hearing are appropriate his response is a resounding **"NO".**
>
> Based on his method of using historic averages as a basis for setting the Total Fuel Costs per MWH to be included in required revenues he concludes that the appropriate level is $27.25 per MWH as opposed to NSP's proposed $29.56 per MWH.
>
> This 7.8% reduction would amount to a decrease in fuel and purchased power costs of $29.4 million ($377.1 x .078). Of this, approximately $23.5 million would be applicable to the above-the-line revenue requirement.
>
> We would agree with the estimates placed in evidence by Dr. Stutz.
>
> (MEUNSC, Final Brief, p. 8, emphasis in original)

[78] The Province, in its confidential closing submissions, avoided making recommendations regarding the issue of imprudency. Like Dr. Stutz, it suggested that test year fuel costs should be normalized. The Province also urged the Board to require NSPI to improve its fuel purchasing guidelines.

4.1.3 Findings

[79] The Board has carefully considered the evidence heard with respect to NSPI's fuel procurement strategy and actual practices. There is no question that, in the 2002 rate decision, the Board stopped short of finding NSPI's fuel procurement to be imprudent. The Board understood that with the closure of Devco, and the end of the majority of NSPI's coal supply coming from domestic sources, NSPI had to begin purchasing much of its fuel supply in the international market. The Board believed that NSPI, at that time, was relatively inexperienced in international coal markets and that the Company should be provided with a fair opportunity to make the changes necessary, in both its organizational structure and in fuel procurement practices, to address this important change in its coal supply procurement.

[80] The need for change was clear in the evidence during the 2002 rate case, especially in the evidence offered by Ms. Medine. The prudency and effectiveness of a balanced portfolio of short, mid-term and long-term coal contracts was unquestionable. In the present case, Avon reminds the Board of her 2002 evidence, stating:

> Emily Medine who testified on behalf of NSPI in this rate case confirmed that in the 2002 rate application she had identified NSPI's approach to coal procurement as imprudent because of NSPI's failure to have a balanced portfolio in place. She described a portfolio for NSPI whereby 50% of its coal procurement should be acquired on long term three to ten year contracts, 25% on medium term contracts of one to three years and the remaining 25% on a spot market basis. Her opinion was that a portfolio approach should result in the lowest long-term costs for the utility.
>
> As early as 2002, Ms. Medine was warning:
>
>> The higher 2002 NSPI prices cannot all be attributed to market. NSPI had not developed a balanced procurement portfolio for its import supplies, making it totally exposed to annual market swings.

> Ms. Medine confirmed that her views on the benefits of the portfolio strategy generally, and also particularly with respect to NSPI have not changed since 2002. Furthermore, she continued to express concerns about the lack of long term coal contracts when she reviewed NSPI'S fuel procurement and reported September 15, 2003 ...
>
> Ms. Medine also noted on that same report that NSPI had not to that point approached procurement of longer term contracts in any meaningful way. On cross-examination by Mr. Grant, Ms. Medine also expressed concern that from a sellers perspective they would not perceive NSPI as being serious about its desire to enter into long-term contracts.
>
> (Avon, Closing Submission, pp. 20-21)

[81] The Board has carefully reviewed NSPI's defense of its coal procurement strategy since 2002. As NSPI points out, it hired Ms. Medine as an expert in this area; it developed a Fuel Procurement and Procedures Manual which was completed in July of 2004; and it has complied with the Board's 2002 directives to return the coal procurement function to NSPI from Emera. NSPI asserts that it has taken reasonable and necessary steps to improve fuel procurement. According to NSPI, the fact that it currently has no long-term imported coal supply contracts does not fairly represent its revised procurement strategy. As NSPI explains it, during the period of time in question, mid or long-term coal supply contracts were inadvisable, either because of limited interest on the part of suppliers or unduly high prices.

[82] The Board acknowledges that certain of NSPI's fuel procurement processes in 2002 have changed considerably since that time. In 2002, NSPI was relatively inexperienced in terms of importing coal. The Board's findings as to whether NSPI's coal procurement practices in 2002 were imprudent were based on whether the strategy and practices used by NSPI were reasonable and prudent under the circumstances. As noted earlier, at that time, the Board did not find NSPI's coal procurement to be imprudent as it believed NSPI should be given a reasonable opportunity to react to the fairly abrupt end

to its reliance on domestic coal supply. This "opportunity" should have involved NSPI quickly acquiring the necessary in-house expertise for imported coal purchasing and expediently revising its purchasing practices to reflect the new reality of the international coal market supply.

[83] It is clear that NSPI took several important steps toward this goal. In early 2003, NSPI engaged Ms. Medine as an external coal consultant and began to develop a Fuel Procurement and Procedures Manual. Ms. Medine's advice regarding the need to have a mixed balance of short, mid and long-term coal supply did not change since her 2002 analysis. Her evidence at this hearing is consistent with her earlier advice. What she could not confirm was whether NSPI had acted quickly and effectively enough to actually implement recommended and necessary improvements in its fuel procurement activity.

[84] The Board has reviewed the submissions of NSPI, and certain of the other intervenors, with respect to the issue of imprudency. NSPI, in its rebuttal evidence addresses the standard for prudency and cites the following as an established definition of this issue:

> As noted in the testimony of John Stutz, certain ratemaking principles must guide the Board in its review of NSPI's proposed 2005 Rates. The presumption in rate making, of course, is that a utility will recover in its rates its prudently incurred expenses. With respect to fuel costs, there are also standard principles which Dr. Stutz and the other consultants fail to recognize.
>
> The standard for determining prudency of a utility's fuel procurement practices is well established. As stated by the Illinois Commerce Commission, "prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made….Hindsight is not applied in assessing prudence….A utility's decision is prudent if it was within the range of decisions reasonable persons might have made. … The prudence standard recognizes that reasonable persons can have honest differences of opinion without one or the other necessarily being imprudent.
>
> (Exhibit N-42, pp. 28-29)

[85] NSPI also argues that the standards applicable to management audits should apply to the review of NSPI's fuel procurement practices, including those performed by Liberty experts.[12]

[86] Avon, in its closing submission, sets out a number of factors to be considered by the Board in determining whether NSPI was imprudent:

> NSPI's inexperiences in the international coal market as of 2002 and the steep pitch of the learning curve in this field were circumstances which the Board found as mitigating considerations in addressing the prudence of NSPI's coal procurement strategy. These can no longer be considered mitigating circumstances. After being battered in the 2002 hearing concerning its approach to coal procurement and receiving the decision of the Board which could only be interpreted as requiring urgent, focused and timely correction, NSPI deserves to be judged in its 2005 application against a higher standard in this most important area of its business.
>
> It is inexplicable that NSPI's 2005 Rate Application reflects procurement of the entirety of it[s] seaborne coal requirements in 2005 by spot contracts having a term of one year or less. NSPI's failure to hedge its exposure to a spike in coal prices in 2005 has caused a large portion of its increased revenue requirement.
>
> Not having a portfolio of coal contracts in 2002 was imprudent and it remains imprudent in 2005. If anything, it is even more imprudent and unreasonable in 2005 that NSPI knew that to meet lower sulphur dioxide emissions requirements it would have to purchase low sulphur coal. Given its reliance upon self-unloading vessels, NSPI was essentially restricted to suppliers from the eastern seaboard of North America, Columbia and Venezuela.
>
> (Avon, Closing Submission, p. 3)

[87] SEB also provided helpful material on the question of imprudency:

> In its Rebuttal Evidence (Exhibit N-42 [N-44 confidential]) NSPI, through Ms. Emily Medine, raises the issue of the prudence standard as defined by the Illinois Commerce Commission. During various portions of its cross-examination NSPI referred to this Illinois Commerce Commission definition. SEB submits that this (and any other) definition of prudence must be viewed in the wider context of the actions of the utility that led up to the decisions in question, as this Board and various other courts and commissions have found in the past. The following discussion sets out this wider context, particularly as it applies to NSPI's obligations as the incumbent monopoly electric supplier.
>
> Subsection 45(2) of the Nova Scotia *Public Utilities Act* provides as follows:
>
>> "Such return shall be in addition to such expenses as the Board may allow as <u>reasonable and prudent and properly</u>

---

[12]Exhibit N-44, p. 29

> chargeable to operating account, and to all just allowances made by the Board according to this Act and the rules and regulations of the Board" [Emphasis added.]

In general, the starting point is the presumption that the expenses of a utility are prudent. However, once a doubt is raised about a given investment or expense, the burden shifts firmly to the utility to demonstrate that the investment or expense was both reasonable and prudent (see for example: *Gulf States Utilities Company v. Louisiana Public Service Commission* (578 So. 2d 71, Util. L. Rep. P 26,061 (West) p. 16); and *Entergy Gulf States, Inc. v. Public Utility Commission of Texas* (112 S.W. 3d-208, Util. L. Rep. P26,862 (West) p. 8).

To meet this burden, the jurisprudence imposes a clear requirement that the utility produce evidence of what the decision was based upon. The decision-making process includes:

> ". . . decision inputs, assumptions, forecasts and studies which might have affected the decisions made by management." (*Gulf States Utilities Company, ex parte Louisiana Public Service Commission* (1988 WL427505 (La. P.S.C.) (West) p. 8)

Furthermore, in *Gulf States Utilities Company v. Public Utility Commission of Texas* (841 S.W. 2d 459, Util. L. Rep. P26,337 (West) p. 19) it was noted that:

> "[a] utility without contemporaneous evidence to support is decision-making process faces a heavy burden . . ."

Accordingly, not only does NSPI bear the burden of proving that its decisions were prudent, but they are also required to put forward evidence of what activities it undertook to underpin those decisions. If there is little or no evidence of facts, actions, analyses, etc. upon which the utility could reasonably have based a carefully thought-out decision, then it has not discharged its burden of demonstrating that the decision itself is prudent. ...

SEB agrees that a utility's decision should not be found imprudent merely because, with the benefit of 20/20 hindsight, a different decision would have been made. However, as the Board will note from the jurisprudence, there is a heavy burden on the utility to show evidence that supports its decision making, and such decisions must be shown to be the result of a logical process guided by a reasonable set of considerations and based on information that is both relevant and sufficiently comprehensive. As will be noted in various sections of this Argument, SEB is of the view that NSPI has clearly failed to meet this burden in relation to a number of matters.

(SEB, Final Argument, pp. 9-12)

[88] The Board has reviewed the case law cited by the intervenors and NSPI on the question of the acceptable legal standard for a finding of imprudency. As SEB notes, **s. 45(2)** of the **Act** identifies that expenses which the Board may allow a utility to charge must be "... reasonable and prudent and properly chargeable ...". The Board agrees with Avon and SEB that, while expenses are generally presumed to be prudent, when questions

are raised with respect to prudency, the burden falls to the utility to satisfy the regulator that its actions were prudent and reasonable.

[89] While the Board recognizes that the definition of imprudence varies somewhat among the jurisdictions cited, there are several fundamental principles which are common. These include:

- Were the utility's decisions reasonable in the context of information which was known (or should have been known) at the time?
- Did the utility act in a reasonable manner and use a reasonable standard of care in its decision-making process?
- The imprudency test should relate to the circumstances at the time in question and not to hindsight.

[90] While several cases were cited on this issue by the parties, NSPI referred in particular to a decision of the Illinois Commerce Commission noted earlier. Following a review of the cases, the Board finds that the definition of imprudence as set out by the Illinois Commerce Commision is a reasonable test to be applied in Nova Scotia.

[91] Accordingly, the Board has focused on NSPI's performance with respect to fuel procurement on the basis of the circumstances confronting NSPI in late 2002 and 2003. In the context of that test, the Board believes the circumstances at the time are reflected in the 2002 hearing and decision. NSPI faced a significant change in its coal supply. It lacked high-level in-house expertise in the international coal market. It defended allegations of imprudence in coal procurement in 2002 and, while the Board did not make a finding of imprudence, it categorized NSPI's coal procurement as "... lacking in sophistication ..." and "... sufficiently lax so as to undermine NSPI's ability to ensure ... that

coal was obtained at the lowest possible price...".[13] In terms of the process for decision-making used since 2002, it has been criticized by Liberty witnesses as lacking in efficiency and accountability. NSPI does not appear to have quickly retained high-level in-house expertise in the international coal market. It is compelling that all of the fuel experts, including Ms. Medine, confirmed that coal prices declined in late 2002 through to mid-to-late 2003. NSPI did not obtain a single long-term coal supply contract during this time.

[92] The issue, in the Board's opinion, is not NSPI's stated intention to improve its practices but the timeliness and effectiveness with which actual implementation of the new approach was achieved. NSPI, in the Board's view, failed to address its imported coal procurement problems quickly or efficiently enough to adequately protect itself or its ratepayers. Had it done so expeditiously following the 2002 rate hearing, the Board is satisfied that, based on the evidence at this hearing, it was possible for NSPI to create a balanced portfolio of short, mid-term and long-term imported coal at reasonable prices. Instead, NSPI appears to have slowly implemented the necessary changes to its procurement practices. It remains unclear to the Board whether the corporate philosophy actually changed, and whether the procedures and practices recommended by Ms. Medine are yet fully implemented, particularly with respect to the need for long-term coal supply contracts which exceed terms of twenty-four months.

[93] There is no question that, following the directives issued in the Board's 2002 decision, NSPI had a number of changes to be implemented concerning fuel procurement.

[13] Board Decision, Oct. 23/02, pp. 27-28

It is possible that, in its effort to comply with other Board directives, the necessary changes to its procurement strategy were not dealt with as urgently as should have been the case. However, the practical reality of the need for many of the changes ordered in the 2002 decision was that NSPI had inappropriately transferred core utility functions to Emera without the approval of the Board. To the extent that compliance with the Board's 2002 directives may have had an impact on the alacrity with which NSPI implemented fuel procurement process changes in late 2002 and early 2003, any delay in this regard is attributable to the decisions made by the Utility and Emera. Any financial impact as a result of delay in implementing these changes, specifically with respect to the higher cost of imported coal in 2005, should not be borne by ratepayers.

[94] NSPI now faces a spot market for coal supply that has spiked. Consequently, NSPI and its ratepayers are confronted with higher than necessary fuel costs. The Board finds that NSPI has been imprudent in its fuel procurement practice and, accordingly, it is not fair or reasonable to permit the total of these costs to be passed on to ratepayers. The Board wishes to make it clear that, in its view, this is not a reflection on the integrity or intentions of individuals, particularly those who were part of NSPI's fuel decision-making process. It does, however, reflect a corporate philosophy which did not change with the urgency and purpose required in the circumstances. NSPI, as a result of its management decisions, now faces changing and higher market prices. It will pay higher coal prices because it is almost completely subject to the vagaries of the short-term market for imported coal.

[95] While the Board finds that NSPI has been imprudent in its fuel procurement practice, it does not believe that the approximately $30 million reduction, which was suggested by a number of the parties, is an appropriate amount.

[96] The primary reason the Board does not agree with the suggested $30 million reduction is the relatively limited period of time during which coal prices declined. Even if NSPI had acted as quickly as it should have to change its procurement strategy and build a balanced portfolio of short, mid and long-term contracts, it had, at best, several months to do so. Considering that part of this time would be required to implement the necessary changes, NSPI had a relatively short period of time to take advantage of the decline in imported coal prices.

[97] The Board believes that an $18 million reduction in fuel costs, rather than $30 million, strikes a reasonable balance on this issue. Accordingly, the cost of fuel and purchased power approved by the Board for the 2005 test year is reduced from $377.1 million to $359.1 million. NSPI is directed to adjust its expenses in this regard in a Compliance Filing following the issuance of this decision.

4.2 Affiliate Activity

4.2.1 Submissions - NSPI

[98] As indicated earlier in NSPI's description of its fuel procurement decision-making process, it identified Todd Sattler as part of the group of individuals (fuel strategy table) who make decisions on fuel procurement. Mr. Sattler wears a number of hats. He

is Vice President of Energy Services for NSPI and he holds similar positions with Emera Energy Inc. and Emera Energy Services Inc.

[99] Mr. Huskilson and Mr. Tedesco confirmed Mr. Sattler's role with both Emera and NSPI in the following response to questioning by Avon Counsel:

Q. May I refer you to Exhibit N-29, Board IR-193? This is an organization chart for NSPI's in-house fuel expertise and procedures.

A. (Tedesco) Yes, it is.

Q. And it shows on the right hand side of the page under Todd Sattler the front office of NSPI responsible for fuel procurement, physical and financial gas trading, scheduling of NSPI generation assets and electricity imports and exports for NSPI.

A. (Tedesco) That's right.

Q. And Mr. Sattler, while he's Vice-President of Energy Services for NSPI, also holds the same title for Emera Energy.

A. (Tedesco) That is correct.

Q. And Mr. Sattler's reporting function is to Mr. Huskilson in his capacity at Emera rather than to you in your position at NSPI.

A. (Tedesco) That, too, is correct.

Q. Isn't that right, Mr. Tedesco?

A. (Tedesco) Yes. Yes, it is.

Q. Thank you.

A.. (Huskilson) And I think just to clarify the reporting structure, we've gone through a bit of a transition, as you know, over the last little while starting about in July of 2003 and ending November 1st when I assumed responsibilities for Emera and NSPI as CEO. Part of this structure is sort of in the middle of that transition. In fact, Mr. Sattler was reporting to me as COO of Nova Scotia Power initially and, as Mr. Tedesco came on board and I moved in to the office of the CEO -- so as COO of Emera I was actually within the office of the CEO, both of Nova Scotia Power and of Emera. And so it was really a movement of Mr. Sattler from the office of the COO of Nova Scotia Power to the office of the CEO of Nova Scotia Power that occurred at this time, so if you look today at the structure, Mr. Sattler still reports to me as President and CEO of Nova Scotia Power. And I think that may help in that transition to clarify just why we went through those organizational changes.

(Transcript, Nov 16/04, pp. 171-173)

[100] Mr. Sattler's activities at NSPI were further described by Mr. Tedesco in response to questions from Board Counsel:

Q. Mr. Tedesco, what are Mr. Sattler's duties as Vice- President of Energy Services for NSPI? I'm not asking for a day-to-day list but his major responsibilities

A. (Tedesco) Mr. Sattler is a very experienced participant in fuel markets across North America, and the expertise that he brings particularly with regard to gas and oil have been extraordinarily valuable to us.

Q. I'm sorry ---

A. (Huskilson) Specifically, though, he supervises the front office of Nova Scotia Power.

Q. Yes. Okay. And that's the front office we've seen in the org. charts and so on.

A. (Huskilson) Yes, that's correct. One thing I'd just like to point out is that this organization is an organization that has been vetted through a process from the orders of 2002 and the organization -- we've worked with Emily Medine on the subject. We've also filed this organization with the Board in 2003 and we've -- and I think we've answered IRs and so on on the subject, and I didn't know whether you were aware of that fact or not but I think it is something that has been in the works for some time.

Q. I'm well aware of that, Mr. Huskilson. Mr. Huskilson, can you tell me what Mr. Sattler's responsibilities are as Vice-President of Energy Services with Emera Energy Inc. and Emera Energy Services Inc.?

A. (Huskilson) Again, he supervises the front office of those operations. Each of the operations within the business have their own front office with their own Director responsible for the management of that office, and that's where the line is drawn between Nova Scotia Power and the other affiliated companies is at that Director level.

Q. Okay. So he supervises the front offices, so-called, of all three organizations.

A. (Huskilson) Yes, that's correct.

Q. And does he or any Emera employees who report to him engage in negotiations or commercial transactions with NSPI?

A. (Huskilson) Certainly the leader of the front office, Wayne O'Connor, would certainly negotiate with NSPI.

Q. Okay. And Mr. O'Connor would report to Mr. Sattler?

A. (Huskilson) Yes, and Mr. Sattler reports to me.

Q. Okay. And Mr. Tedesco, would Mr. Sattler or any employee of NSPI who reports to Mr. Sattler engage in negotiations, commercial transactions with Emera Energy Inc. or Emera Energy Services Inc.?

A. (Tedesco) I'm sorry, if you could repeat that, would Mr. Sattler ---

Q. Or any NSPI employee who reports to him engage in negotiations or commercial transactions with Emera Energy Services Inc. or Emera Energy Inc.?

A. (Tedesco) Yes.

Q. So he is on both sides of those transactions, so to speak.

A. (Tedesco) Yes, he is, and any of those transactions are conducted consistent with the company's code of conduct and, as Mr. Huskilson mentioned a moment ago, they are conducted consistent with the organization that was filed with the Board in 2003.

A. (Huskilson) And I think, Mr. Outhouse, as a practical matter, I mean, so am I obviously.

Q. Yes.

A. (Huskilson) And I think when the front office of NSPI is negotiating with the front office of Emera Energy clearly, at that point, the dotted line relationship between Mr. Tedesco and that front office Director is in force at that point.

Q. I understand that, I guess, Mr. Huskilson, but the fact remains that Mr. Sattler, at least, is in charge of all three of those front offices.

A. (Huskilson) Absolutely, as am I.

(Transcript, Nov 18/04, pp. 468-471)

[101] Board Counsel also questioned NSPI as to whether NSPI's fuel strategy table, and Mr. Sattler's presence there, was consistent with the Board's 2002 rate decision.

Q. And do you believe that it's consistent with the Board's directive that you just read for representatives of Emera, that's you, Mr. Huskilson, at least when you sat in that capacity, and for Mr. Sattler, to sit on the fuel strategy table, NSPI's fuel strategy table?

A. (Huskilson) Well, first of all, neither myself or Mr. Sattler sat in that capacity, Emera's capacity.

Q. Well no, you are the same individuals though, correct?

A. (Huskilson) Sure, absolutely.

Q. Yes. All right. So you had a duty, in some sense, to Emera. You had a duty, in some sense, to NSPI.

A. (Huskilson) Well, I think under the code of conduct we would have had a duty to NSPI in that particular circumstance. I mean, as you know, we're a small company and as a small company it is -- and I think the code of conduct quite rightly recognizes the fact that there will be overlaps in responsibility, that's part of the efficiency that can be bought by using a code of conduct as we have, and by having the relationship that exists with Emera. And so, you know, there are going to be these kinds of overlaps.

Q. I'm going to ask you to turn to what I have marked as paragraph 385 in the decision, and yours may be off by one.

A. (Huskilson) I'm sorry, could you repeat that please?

Q. Turn to paragraph 385 which should put you in the vicinity, I hope, and it's under the heading "Independence and Insulation." That's the heading you'll see. ...

Q. This paragraph reads: "The Board became increasingly concerned during the hearing with respect to the apparent lack of separation between NSPI and Emera and how this could negatively impact ratepayers. It is imperative in the Board's view that NSPI and Emera avoid becoming so integrated that senior management is conflicted between the interests of Emera shareholders and the interest of NSPI ratepayers. It is clear to the Board that these interests can diverge from time to time." Do you see that?

A. (Huskilson) I do, which is precisely why we have appointed a COO responsible for NSPI and solely responsible for NSPI. When I was COO of NSPI I had multiple other responsibilities, and Mr. Tedesco does not. So he is the person who is solely responsible for NSPI relative to its operation, relative to its decision making, and relative to all of these various pieces. And so any of the decisions that are made in conjunction with what you're talking about really fall to him in the end, and that's why he chairs the table. Some of what you might be concerned about is the transition that occurred but, you know, the practicality of needing to make a transition is something that has to be dealt with as those kinds of things happen.

Q. And perhaps, Mr. Huskilson, if I can say so, I understand from your perspective about the transition. Mr. Sattler's role, as I understand it, is not transitional. He holds the same responsibilities in all three companies, and I guess the question is what assurance does the Board have that decisions made by those front offices or the fuel strategy table, particularly I should have said the front office of NSPI and its fuel strategy table, will be made solely, bearing in mind the self-interest of NSPI, and without any regard whatever to the interests, perhaps competing interests, of the Emera companies?

A. (Tedesco) Well, Mr. Outhouse, that would be my responsibility. As Chair of the fuel strategy table I take input from these folks. My sole interests are NSPI and NSPI's customers when those decisions are rendered, and I believe that Mr. Sattler's responsibilities are as filed in 2003. I do not believe there have been any changes in that regard.

Q. You've referred to the 2003 filing. It's not my understanding that the Board has ever sanctioned the arrangement which exists, is that right?

A. (Tedesco)That is correct. And it's also the case that we have received no objection, either.

Q. You've received a number of IRs which you have answered.

A. (Tedesco) That is correct.

Q. And that's the status of the matter.

A. (Tedesco) At present that's correct.

Q. Okay. Now, the Board in its decision, and I've already read you the passage, alluded to the conflict of interest or certainly the potential conflict of interest which can occur. Do you agree with me that the potential for such conflict of interest still exists, nothing has changed?

A. (Tedesco) No, I think the controls that we have in place, the responsibilities I have, our code of conduct, and the transparency of our fuel transactions, I think all speak to that issue rather forcefully.

Q. But you would agree with me, Mr. Tedesco, that the potential for conflict is inherent in any commercial negotiation.

A. (Tedesco) I think negotiations often have conflict in them, if you're referring to conflict in the sense of disagreements.

Q. Sure.

A. (Tedesco) If you're referring to it in any other form with specific regard to the fuel strategy table I would not agree.

Q. Buyer/seller as between front offices there's clearly a potential conflict, there is a conflict of interest. One wants the best deal it can get, and the other wants the same.

A. (Tedesco) Yes, and as the buyer or seller for NSPI again my sole interest is that of the company and its customers.

Q. Okay. But you have already said, as I understood you a few moments ago, that Mr. Sattler has great expertise in fuel matters on which the company has relied.

A. (Tedesco) That is correct.

Q. And do you rely on him?

A. (Tedesco) On occasion I do.

Q. Is his expertise in fuel matters greater than yours?

A. (Tedesco) In many areas, yes.

Q. Okay. What role, if any, did the fuel strategy table play in the decision by NSPI to sell natural gas to Emera Energy?

A. (Tedesco) it was reviewed and approved by the fuel strategy table.

(Transcript, Nov 18/04, pp. 474-481)

[102] In NSPI's confidential closing submission, criticism of intervenors with respect to Mr. Sattler's participation in the fuel strategy table and the conflict of interest issue they raised were addressed. NSPI pointed out that it has taken a number of measures to comply with the Board's 2002 directives, including returning fuel procurement activity from Emera to NSPI. It indicated that Mr. Sattler's dual role, and his participation in the fuel strategy table do not conflict with the Board's findings and directives in its 2002 decision. It further states that it views the Code of Conduct as a very important document and has exerted considerable effort to ensure compliance with the Code. It also pointed out that it reported its organizational structure, including Mr. Sattler's role, to the Board and, while no approval was received, no criticism or alternate direction has been issued by the Board.

4.2.2 Submissions - Intervenors

[103] A number of intervenors have raised concerns surrounding Mr. Sattler's role with NSPI and Emera. In the cross-examination of Liberty witnesses during the *in camera* fuel sessions, Nancy Rubin, Counsel for Avon, raised the issue of Mr. Sattler's compensation. While this occurred during an *in camera* session, the Board does not believe the reference requires confidentiality. Referring to Exhibit N-7, Tab 2, the management information circular (a non-confidential document), she noted that:

> Q. For 2003, it lists annual salary of a hundred and eighty-one thousand, seven thirty-one. Other annual compensation of a hundred and ninety-eight thousand, four thirty-one. And there's a footnote No. 11. And that footnote states that Mr. Sattler's contract provides for an annual supplement to his salary -- "see employment contracts for further details." And then if you flip a few pages ahead to page 18, under the heading, "Other named executive officers," and in the second paragraph, it discusses Mr. Sattler's contract, and it states that:
>
> > "An annual incentive equal to two percent of earnings before interest and income tax from the business operations of energy services or 100 percent of annual salary, whichever is greater."
>
> I'm just wondering if you were aware of this incentive related to energy services and if you can comment on this.
>
> A. (Spangenberg) We were not aware of this specific provision of his compensation.
>
> A. (Adger) I was not aware of it either. I would just add to what you said that it looks like he has an important incentive to expand the earnings of the unregulated affiliate.
>
> (**Confidential** Transcript, Nov 30/04, pp.2564-2565)

[104] In its redacted evidence, Liberty also identified areas of concern relating to potential conflicts of interest and affiliate activities relating to both Mr. Huskilson and Mr. Sattler:

> Fifth, the VP of Energy Services has split responsibilities between the regulated entity of NSPI and the non-regulated activities of Emera Energy. He is the VP of Energy Services for NSPI, and he is also the VP of Energy Services for Emera Energy. This is unsatisfactory, and represents a material conflict of interest. The essence of this conflict is that NSPI's Front Office sells electricity and gas to Emera's Front Office, which, in turn, resells these products.

> The VP of Energy Services serves as manager of both of the offices that are the buyers as well as the sellers in these transactions.
>
> Sixth, there is an affiliate relations conflict on the membership of the Fuel Strategy Table. The membership of this group consists of five individuals, the COO of Emera Inc., the COO of NSPI, the VP Energy Services, the GM Power Production, and the Director of Energy, Fuels and Risk Management. Two of these individuals, also serve in the capacity as senior managers with Emera – the COO of Emera, and the VP Energy Services. This is unsatisfactory, and represents a material conflict of interest, considering this group has major decision-making responsibility for fuel procurement for NSPI.
>
> (Exhibit N-136, pp. 31-32)

[105] In their evidence during *in camera* portions of the hearing, both Mr. Spangenberg and Mr. Adger voiced concerns about Mr. Sattler's dual role with Emera and NSPI and about affiliate relations in connection with gas sales. John Antonuk, another witness from Liberty, expressed the view that incentive compensation should be paid to utility employees on the basis of the performance of the utility and should not be based, in large part, on the performance of unregulated affiliates. Dr. Stutz, in his evidence, expressed similar concerns relating to Mr. Sattler and Mr. Huskilson:

> **Q. PLEASE DESCRIBE NSPI'S NEW ARRANGEMENTS.**
>
> NSPI's new arrangements rely on a mix of "groups" and "offices", some of which are part of Emera. The Company's response to UARB IR-121 and 245 describes the offices and groups. The Fuels Strategy Table has overall responsibility for NSPI's fuel strategy. Members of this table are the Chief Operating Officer (COO) of NSPI (Mr. Tedesco), who chairs the table; the COO of Emera (Mr. Huskilson); the GM of Power Production (Mr. Taylor); the VP, Energy Services for NSPI (Mr. Sattler); and the Director of Energy, Fuels and Risk Management (Ms. Lambert). Beyond the Fuels Strategy Table there are two primary groups that deal with fuel. Energy, Fuels and Risk Management (EF&RM), reporting to Mr. Taylor, is responsible for fuel-related planning and forecasting, including development of overall strategy recommendations, progress monitoring, and reporting on strategy execution. NSPI's front office, reporting to Mr. Sattler, executes the strategy and plan developed by EF&RM and deals with asset optimization on a day-to-day basis.
>
> **Q. DO YOU HAVE ANY CONCERNS ABOUT THESE ARRANGEMENTS?**
>
> Yes, I do. My concerns center on two individuals, Mr. Huskilson and Mr. Sattler, who are at NSPI's Fuels Strategy Table. Mr. Sattler is VP, Energy Services for Emera Energy Inc., and Emera Energy Services Inc, as well as VP, Energy Services for NSPI. Inclusion of Mr. Huskilson and Mr. Sattler on NSPI's Fuel Strategy Table does not appear to meet the Board's directive that NSPI resume full responsibility for its

own fuel-related core functions. Mr. Sattler's dual roles at NSPI and Emera raises particular concern in light of the following point, made in the Board's order in the Last General Rate Proceeding:

> It is imperative, in the Board's view, that NSPI and Emera avoid becoming so integrated that senior management is conflicted between the interests of Emera's shareholders and the interests of NSPI ratepayers, it is clear to the Board that these interests can diverge from time to time.

In considering the point just raised, it is important to understand that it is not Mr. Sattler or Mr. Huskilson per se, but rather their positions within NSPI's fuel-related arrangements that is the concern.

Q. DO YOU SUPPORT CONTINUATION OF NSPI'S NEW ARRANGEMENTS?

No. I recommend NSPI reorganize its arrangements so that the core fuel-related functions are **fully** within NSPI and real or apparent conflicts of interest are avoided. In considering this recommendation I would ask the Board to take into account the evidence of the other Board Staff witnesses addressing fuel-related issues.

(Exhibit N-134, pp. 34-35, emphasis in original)

[106] At the hearing, Dr. Stutz elaborated on his concern when questioned by the Board:

Q. ... Do you have any comments concerning the affiliate relationship between NSPI and Emera as it has been raised from time to time during this hearing, for example the sale of gas from NSPI to an Emera affiliate which then resells it, the issue of the fuel table at which sits both Emera and NSPI personnel?

A. I do, and before I answer I just wanted to draw your attention to something but let me get the right reference for it. I can't put my hands on it but I think you'll recognize it when I mention it and maybe someone else can tell me where it is. What I'm thinking about is an organization chart for the fuel procurement process, and the organization chart that I'm looking at, I think it may have come from Ms. Medine's original evidence, I'm not sure, but anyway what it shows is the NSPI front office with various other functions reporting to it. So into the front office it shows gas, heavy fuel oil, power, coal, etcetera, and then it has the Emera Energy Services front office with gas and power reporting into that, and the two of them reporting to the same individual who, I understand, is Mr. Sattler. Now, that is a degree of interconnection that could conceivably give rise to concern. I was concerned about it primarily because of what you wrote in the last order on insulation. It didn't seem to me that a senior executive who was in that box to which both of these trains of command reported could have the degree of insulation that you wrote about in your last order. So if the standard is insulation as you described it in your last order, this organization chart, as I understand it, doesn't meet that standard. If the standard is that "We can have whatever organization chart we want as long as we abide by the code of conduct" then I would have to reserve judgment because maybe the code of conduct is adequate to handle the situation, but it certainly wasn't adequate to handle what I read in your order.

Q. So you're talking primarily about the fuel strategy table, is that correct?

A. Yes.

Q. What about the other aspect that I mentioned or asked you about, Dr. Stutz, the issue of the sale of gas from NSPI to an Emera affiliate? Do you include that in your comments or do you consider that somewhat different?

A. No, I include it in my comments for this reason. I understand that the portion of NSPI that undertakes the sale and the portion of Emera that would be purchasing all report to Mr. Sattler. Now, Mr. Sattler may have some form of what is often referred to as a Chinese wall, which makes that appropriate, but it didn't seem to satisfy your insulation concern.

(Transcript, Dec 3/04, pp. 3438-3440)

[107] Avon, in its closing submission, argued that NSPI has not adequately complied with the Board's 2002 decision regarding affiliate transactions. Avon points out that:

> The current organizational chart for NSPI's fuel procurement shows the front office for NSPI responsible for fuel procurement, physical and financial gas trading, scheduling of NSPI generation assets, and electricity imports and exports for NSPI, reporting to Todd Sattler, the VP Energy Services for NSPI. Mr. Sattler also holds the position of VP Energy Services for Emera Energy. Mr. Sattler reports directly to Chris Huskilson, COO of Emera. Mr. Sattler does not have a reporting relationship through Mr. Tedesco, COO of NSPI.
>
> Either Mr. Sattler or employees of NSPI reporting to him are engaged in negotiations or commercial transactions with Emera Energy Services Inc. or Emera Energy Inc. Mr. Sattler's expertise in fuel matters exceeds that of Mr. Tedesco and understandably Mr. Tedesco relies greatly upon Mr. Sattler in fuel matters.
>
> NSPI argues that the arrangement has sufficient insulation and independence for NSPI in that Mr. Tedesco chairs the Fuel Strategy Table and is solely responsible for NSPI. NSPI also refers to its Code of Conduct and "the transparency of our fuel transactions". It is difficult to understand what NSPI means by "the transparency of our fuel transactions" when the reports on affiliated party transactions are sheets of line entries with short descriptions of the transaction and a description of the pricing mechanism as either "fully allocated cost", "fair market value" or "fairly allocated cost" with no description of the units involved in the transaction or the basis upon which the value was ascertained.
>
> With respect to fuel transactions, the concept of "transparency" has to be modified to account for the fact that information pertaining to these transactions is not widely disclosed as they are subject to confidential agreements.
>
> The lack of insulation by NSPI in its fuel procurement raised concerns on the part of a number of witnesses. This concern was heightened by the consideration that Mr. Sattler is eligible for an annual incentive equal to two percent of the earnings before interest and income tax from the business operations of Emera Energy Services.
>
> Mr. Adger described this as an important incentive to expand the earnings of the unregulated affiliate. Mr. Antonuk stated that as a general principle, utility employees should have their incentive compensation based upon utility results and that no significant portion

of their bonus or incentive compensation should relate to non-utility activities. The reason for this is to take away as many incentives as possible from the employees to support the holding company or the non-regulated side at the expense of the utility.

Concerns respecting the lack of insulation are heightened by the criticism by the Board's expert, John Adger, of the solicitation process and resulting agreements for the sale of natural gas not used in NSPI generating facilities and whether they achieve the optimum benefit for NSPI ratepayers. Mr. Adger's recommendation that the Board inquire into the solicitation procedures in an effort to ensure that the annual agreement is not limiting the proceeds that NSPI derives from the sale of natural gas compared to what might be derived under more common seasonal and 30 day agreements also heightens this concern.

As Mr. Adger described the current arrangements for the sale of natural gas by NSPI to Emera, it appears only slightly different from the circumstances prior to the Board's Order in 2002. As Mr. Adger stated:

> *Even in the presence of the Board's instruction to get the affiliate out of the fuel supply business, here the affiliate turns up again buying all of the gas under the [Redacted] Contract and then reselling it into the New England market . . . now they're going to . . . – they've sort of inserted one step, so they're going to give the affiliate at least some piece of the market value of it.*

Mr. Adger's description of the underlying motivation still resonates:

> *Whosever idea it was to move the [Redacted] Contract from the regulated side to the unregulated side without compensation is still in the building, okay, and still looking for stuff to move.*

As Mr. Adger explained, as a general matter, the utility's off system sales activity is really engaged in the same markets as the unregulated affiliate's wholesale trading activities. They are fundamentally in the same business. The wholesale trading activity of the affiliate is buying and selling and the utility is just selling but the utility is selling in the same market.

Mr. Antonuk considered the situation to be one which transcends imprudence and relates to a matter of basic corporate integrity. He raises the question of whether the controls on the enterprise are sufficient to give adequate assurances that the interests of the affiliated company are not being given priority over that of the utility...

The fact that the Vice President of Energy Services for NSPI is eligible to receive an annual incentive equal to two percent of earnings before interest and income tax from the business operations of Emera Energy Services raises a reasonable and justifiable concern as to how he can balance conflicting interests in his dual position as VP Energy Services for NSPI and VP of Energy Services for Emera Energy. He has financial incentives for increasing the volume of transactions and therefore earnings of Emera Energy. His knowledge and experience makes him an influential member of the NSPI fuel strategy table. It is fair to question whether the progressively increasing volume of affiliate party contracts respecting fuel procurement have been influenced by the compensation scheme.

(Closing Submission, Avon, pp. 48-52)

[108] Avon further submits that:

> The lack of independence of NSPI and its lack of insulation from Emera are immediate and significant concerns which have intensified since the 2002 case. We would submit that the Board should make the following orders:
>
> 1. that an independent review be conducted of affiliated party transactions from 2002 to 2004 to ensure NSPI's ratepayers have benefited [sic] from these transactions;
> 2. that the Board order an independent review of the structure of the tendering process, the timing and terms of tenders to ensure they do not favour Emera over other tenderers;
> 3. that the Board order immediately that no employees of Emera (whether employed by Emera alone or in conjunction with NSPI) participate on the NSPI fuel table;
> 4. that no employee of NSPI who is also employed by Emera be engaged in the negotiation of contracts between NSPI and an affiliate; and
> 5. that NSPI be required to prepare and submit a plan which contains specific provisions identifying how it proposes to address the spirit and intent of the Board's direction with respect to NSPI's insulation and independence from Emera.
>
> (Closing Submission, Avon, p. 50)

[109] HRM, MEUNSC and the Province all commented on this issue in their written submissions. The Province states that:

> The Board's decision in the 2002 Rate Case contained a detailed discussion of NSPI's interactions with its affiliates. Among other things, NSPI was required to "resume full responsibility for its own fuel procurement, export electricity sales and gas sales". These were considered by the Board to be core functions of the utility. NSPI complied with this and other Board directives contained in the 2002 Rate Case Decision relating to the Code of Conduct and has demonstrated improvement in a number of areas.
>
> At present, the same individual (Mr. J.T. Sattler) holds the positions of Vice President Energy Services for NSPI, Emera Energy Service Inc. and Emera Energy Inc. Mr. Sattler supervises the "front offices" of each of these companies. Persons who report to Mr. Sattler in each of the above noted Emera companies may engage in negotiations or commercial transactions with NSPI. Further, Mr. Sattler is a member of the NSPI Fuel Strategies Table where major decisions related to fuel procurement and sales are made. This includes the decision to sell natural gas to Emera Energy.
>
> While there is probably much benefit to NSPI from employing someone with Mr. Sattler's background and experience, an exchange between Board Counsel and the NSPI Policy Panel, Chris Huskilson and Ralph Tedesco, highlights the appearance of and potential for a conflict of interest to arise because the same individual occupies the position of Vice President Energy Services for NSPI and two of its Emera affiliates. This potential conflict is heightened by the fact that a portion of Mr. Sattler's remuneration is in the form of "an annual incentive equal to two percent of earnings before interest and income tax from the business operations of [Emera] Energy Services, or 100% of annual salary, whichever is greater".
>
> This issue is brought to the Board's attention to demonstrate the need for ongoing monitoring for compliance with the Code of Conduct requirements. It is submitted that the Board should closely review the current organizational structure of NSPI to ensure that it is in full

> compliance with the Board's 2002 Rate Case Decision and the approved Code of Conduct. Notwithstanding the progress made by NSPI in relation to Code of Conduct compliance, the evidence demonstrates that further work is required to refine processes and increase stakeholder confidence.
>
> (Closing Submission, Province, pp. 30-31)

[110] SEB submitted the following:

> Various parties have noted the ongoing affiliate relationships between NSPI and Emera affiliates. [**redacted**] SEB does not intend to reiterate the record in this regard, but believes that the Board should continue to evaluate whether these relationships are providing value to NSPI. More particularly, in order to ensure transparency and to eliminate any potential for favored treatment of affiliates, the Board should require that NSPI fuel procurement decision-makers be employed only by NSPI, and have no direct employment relationship with Emera or its affiliates.
>
> (Final Argument, SEB, p. 22)

4.2.3 Findings

[111] The Board has reviewed this matter with particular interest in view of its findings in the 2002 rate decision. In that case, as has been noted earlier, the Board expressed considerable concern with NSPI's reliance on affiliated entities to provide fuel procurement services. NSPI's single largest annual expenditure is fuel required to generate electricity. In the Board's view, this made fuel procurement a core function of the Utility and one which should not have been transferred to unregulated affiliates.

[112] The Board acknowledges that NSPI is correct when it states that Mr. Sattler's role was disclosed in its filing of interim and final reports in 2003 concerning In-House Fuel Expertise and Policy and Procedure Development. The Board also acknowledges that it did not engage the services of fuel experts at that time to review these reports. However,

based on the opinions of the various fuel experts engaged in this hearing by the intervenors and Board Counsel, it is clear that valid concerns exist.

[113] The Board agrees with the views of the intervenors and Dr. Stutz with respect to the concerns surrounding Mr. Sattler's dual role with NSPI and Emera and his participation in NSPI's decision-making process on fuel procurement. Like the intervenors, the Board does not question Mr. Sattler's integrity, his expertise in the gas and oil industry or his value to Emera in terms of his work for affiliated companies. However, his integral role with respect to NSPI's decision-making on its largest single expense item is inappropriate, in the Board's view. His incentive compensation arrangements clearly reflect this. He is not compensated on the basis of NSPI's performance. He is compensated on the basis of Emera Energy Services performance. The Board stated in its 2002 decision that fuel procurement is the Utility's core function. Accordingly, it should not be overseen or influenced by individuals whose primary responsibilities relate to unregulated affiliates. The Board also has concern, expressed by Dr. Stutz and others, that Mr. Huskilson's participation as a member of the fuel strategy table does not conform to the degree of insulation required between NSPI and Emera as set out in the Board's 2002 decision.

[114] As referred to in the previous section on fuel procurement and prudency, the Board notes the criticism of intervenors with respect to NSPI's fuel procurement decision-making practices. Mr. Spangenberg pointed out that, in his view, NSPI lacks sufficient in-house expertise on fuel procurement, particularly coal; its fuel procurement solicitation process is not consistent; decision-making is not efficient or accountable enough; nor is there an appropriate delegation of authority to allow individuals to make these decisions.

NSPI's fuel strategy table, which consists of Chris Huskilson, former COO of Emera Inc.; Ralph Tedesco, COO of NSPI; Todd Sattler, Vice-President of Energy Services for NSPI, Emera Energy and Emera Energy Services; James Taylor, NSPI's General Manager of Power Production; and Mary Lambert, NSPI's Director of Energy, Fuels and Risk Management, review all imported coal supply contracts. Mr. Spangenberg believes that NSPI should hire sufficient in-house expertise and set out decision-making authority at various levels, based on contract costs, to improve efficiency and accountability. The Board agrees with this assessment.

[115] Accordingly, the Board directs that Mr. Sattler, so long as he continues to be an employee of Emera Energy or Emera Energy Services, or any other unregulated affiliated company, no longer participate in NSPI's fuel strategy table. NSPI is also directed to promptly engage high level in-house expertise to lead the imported coal supply aspect of its fuel procurement process and to establish a more efficient and accountable decision-making structure with respect to fuel procurement. NSPI is directed to file a report with the Board, within six months from the date of this decision, outlining the implementation of the changes noted above. The Board will engage the services of independent fuel experts to review the adequacy of NSPI's actions to address this issue. While the Board understands the similar concerns expressed regarding Mr. Huskilson's participation in the fuel strategy table, it is not prepared, in view of his positions with Emera and NSPI, to direct his removal from the fuel strategy table and decision-making process at this time.

[116] The Board also notes the concerns expressed with respect to other affiliate transactions involving energy and fuel. It is evident from the issues raised that reviewing

NSPI's annual filing on affiliate transactions solely by an accounting firm, however, well-qualified, is likely insufficient. Accordingly, in addition to the form of review on this information performed in the past, the Board, in future, will also retain fuel audit experts to examine and express their opinions on these types of affiliate transactions, including export sales and natural gas sales.

4.3 Fuel Adjustment Mechanism

4.3.1 Submissions - NSPI

[117] In its initial application, NSPI requested approval of a Fuel Adjustment Mechanism ("FAM"). NSPI explained the proposed FAM as follows:

> A relatively straightforward fuel adjustment mechanism would be a fuel adjustment clause. A fuel target is established (based on forecasts) for the purpose of initially setting rates. If actual fuel costs are above the target the additional costs are recovered from customers. If the actual costs fall in a band below the target the savings are returned to customers.
>
> NSPI appears to be in a minority of utilities in not having a fuel adjustment mechanism. In light of the volatility and uncertainty in fuel markets NSPI is proposing a fuel pass through. The Company wishes to consult with customers, other stakeholders and the Board about the appropriate structure of such a pass through mechanism for use in Nova Scotia.
>
> (Exhibit N-1, pp. 44-45)

[118] NSPI presented the views of Tim Simard, a principal with the firm Risk Advisory, with respect to FAMs. In his November 2, 2004 report, Mr. Simard explained that NSPI is one of only three investor-owned electric utilities in Canada and the only one which

does not have a FAM.[14] Mr. Simard noted that FAMs are also prevalent in natural gas utilities in Canada and common for gas and electric utilities in the U.S.

[119] Following a number of IRs from other parties concerning the FAM, and criticism of experts that the FAM proposed by NSPI was vague and lacked adequate details, a somewhat more refined FAM was described in the testimony of Mr. Tedesco and Mr. Huskilson at the hearing, and in NSPI's rebuttal evidence (Exhibit N-42). NSPI indicates that its initial proposal was deliberately general in order to provide an opportunity for stakeholders to influence the development of the FAM. Mr. Tedesco, under cross-examination by George Cooper, SEB's Counsel, acknowledged that, while NSPI had discussions with stakeholders concerning a FAM, the version proposed in Exhibit N-42 was not the subject of review or comment by other parties prior to filing.

[120] NSPI's comments on the revised FAM are as follows:

> NSPI is offering refinements to the proposed FAM that reflect:
>
> - Input from intervenors
> - A balance between the customer desire for rate stability and the benefits of market-responsive pricing
> - Underlying mechanics that are simple, easy to understand and apply
> - Continued incentive for the utility to optimize its fuel procurement activity
> - An extension of the period during which electricity prices remain unchanged
>
> The proposed FAM includes these elements:
>
> - The adjustment will be described in customer-friendly units of $/MWh or $/KWh.
> - Adjustments will be filed semi-annually, with the opportunity for UARB review.
> - The semi-annual adjustment will contain two components:
>   - o An adjustment to reflect the updated forecast fuel cost for the subsequent half year.

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[14]Exhibit N-42, p. 26

- o An adjustment that allows for the clearing of any outstanding deferral account balance over a subsequent 12-month period acting to levelize rates.

- NSPI will establish a deferral account that will track the difference between the semi-annual forecast fuel cost on a dollar per MWh basis and the actual fuel cost.
- The deferral account balance (either a debit or credit) will bear interest at a rate equal to NSPI's weighted average cost of capital.
- Proximate to the filing of Annually Adjusted Rates, NSPI will also file an annual fuel forecast for the upcoming year for a 30-day period of review and commentary by stakeholders, the UARB and customers would have a 30-day period for review and commentary.
- The UARB or its designate will be invited to participate in matters of fuel procurement at any and all times at the Fuel Strategy Table.
- After each of the first two years of the initiation of the FAM, the UARB is invited to conduct an annual hearing or technical conference with customer participation to review the fuel procurement practices of NSPI over the previous year.

(Exhibit N-42, pp. 87-89)

[121] NSPI submits that, while a FAM shifts the risk of fuel price volatility to ratepayers, NSPI will continue to closely and prudently work to ensure fuel costs are kept as low as possible. As noted in the section of the decision on return on equity, the existence of a FAM is a factor used in determining what constitutes a reasonable rate of return for NSPI. NSPI points out that if the FAM is approved, the return on equity would be lower than would otherwise be the case, as the FAM reduces the fuel cost risk faced by the Company.

[122] Mr. Tedesco and Mr. Simard gave additional evidence regarding FAMs during the *in camera* portion of the rate hearing. Both indicated that FAMs are common in other North American jurisdictions and, to their knowledge, FAMs have only been withdrawn in the US where retail competition has been introduced. NSPI also filed the specific version of the FAM, to be included in its Tariff, in Undertaking U-24.

[123] In the SA filed by NSPI, the request for a FAM was deferred with the following plan for future consideration:

> 4. Board allows for the consideration of a Fuel Adjustment Mechanism (FAM) during 2005 for the calendar year 2006, subject to the following:
>   a. NSPI developing a specific FAM proposal for review by stakeholders at a Technical Conference
>   b. NSPI gaining further experience in international coal markets
>   c. NSPI agrees to a customer education campaign, should its request be favorably considered.
>   d. NSPI recognizes UARB approval of a FAM is required
>
> (Exhibit S-1, Terms of Recommended Settlement)

4.3.2 Submissions - Intervenors

[124] The proposed FAM was widely opposed by the intervenors. Fuel experts, including John Antonuk and Dennis Kalbarczyk of Liberty, essentially took a similar view with respect to why the FAM should not be approved. They all expressed concerns that NSPI's fuel procurement process is inadequate and, since a FAM could reduce or eliminate NSPI's incentive to make necessary improvements to its processes, a FAM at this time would be premature and ill-advised. They also took issue with the generality and vagueness of the initial FAM proposed. Their fundamental objection, even after reviewing NSPI's refined version of a FAM, was that the risk of fuel price volatility should not be transferred to ratepayers until NSPI's fuel procurement was much improved in a number of respects.

[125] Mr. Antonuk and Mr. Kalbarczyk outlined their reasons for recommending against a FAM in their direct evidence:

> NSPI's performance and its proposals in this proceeding do not lay a proper foundation for the introduction of a FAM, for four reasons:
>
> - The evidence of Donald Spangenberg shows the existence of substantial weaknesses in NSPI's management of its fuel and energy. Concerns about the effectiveness of NSPI fuel management substantially diminish the prospects for successfully introducing a new rate recovery method of this type.
> - The evidence of Donald Spangenberg and John Adger raises substantial questions about fuel and energy transactions with affiliates and about whether relationships with affiliates are conducted at arm's length. We believe it is appropriate for a more detailed examination to be made of affiliate relationships before considering the introduction of FAM.
> - Even if the two preceding concerns did not exist, NSPI's proposed FAM, insofar as we can identify its components is not sufficiently well identified, described, and laid out in proper form to provide for a clause with clearly established dimensions and procedures.
> - NSPI's proposal also fails to provide for certain, sufficient regular reviews of forecasted costs, structured, after-the-fact cost reconciliations, and examinations of the prudence and reasonableness of costs subject to FAM recovery.
>
> NSPI's proposed fuel cost pass-through mechanism is therefore premature to consider in the context of this proceeding.
>
> (Exhibit N-135, pp. 3-4)

They stated that:

> We recommend that the Board:
>
> - Not allow at this time the adoption of a FAM.
> - Monitor the effectiveness of fuel and energy management, in order to determine the point at which there is confidence that NSPI is performing at a level that is both stable and effective.
> - Defer to a later proceeding the question of whether it is appropriate to adopt a FAM for NSPI, considering as well in that proceeding the administrative questions not adequately addressed in this one, including structure, components, and protections.
>
> (Exhibit N-135, pp. 4-5)

[126] Dr. Stutz also recommended in his direct evidence that the Board should reject the proposed FAM, stating that:

> **Q. DO YOU SUPPORT THE ESTABLISHMENT OF A FAM FOR NSPI AT THIS TIME?**
>
> A. No, taking all of the above considerations into account, I do not recommend establishment of a FAM for NSPI at this time. In considering this recommendation I would ask the Board to take into account the evidence of other Board Staff

witnesses concerning the adequacy and effectiveness of NSPI's efforts to date to control its fuel-related costs.

Q. DOES YOUR RECOMMENDATION REST ON THE EVIDENCE PROVIDED BY OTHER WITNESSES APPEARING ON BEHALF OF BOARD STAFF?

A. No. In the absence of that evidence I would still oppose the establishment of a FAM at this time. Establishment of a FAM would remove or diminish the incentive for NSPI to manage its fuel costs efficiently and, as shown in the response to NSDOE IR-33, it would adversely affect rate stability. Actions that remove or diminish incentives for utility efficiency and create rate instability should only be taken if they are clearly needed. NSPI's need for a FAM is not yet established.

(Exhibit N-134, pp. 32-33)

[127] Mark Drazen, of Drazen Consulting Group, Inc., an expert witness for Avon, made the following comment concerning NSPI's proposed FAM:

> An automatic fuel adjustment mechanism (FAM), such as requested by NSPI, is not the only way–nor necessarily the best way–of dealing with anticipated variations in fuel cost. The ability to pass through fuel costs reduces the incentive to minimize those costs. This transfers the risk of fuel cost variation to customers and increases that risk. Further, as the recent past shows, NSPI's forecast of fuel costs for the test year is not necessarily representative of the costs that will be incurred in that or subsequent years.
>
> (Exhibit N-91, p. 3)

[128] Mr. Drazen also noted that, while FAMs exist in a number of U.S. jurisdictions, Newfoundland Power is the only Canadian electric utility that has a FAM.[15]

[129] Avon, in its closing submissions, states:

> Thereafter, NSPI revised its proposed FAM and included a new proposal as part of its rebuttal evidence. The "refinements" were stated to reflect, among other things, input from intervenors and continued incentive for the utility to optimize its fuel procurement activity.
>
> It should be noted however that the revised FAM failed to include any mechanism by which cost-sharing between ratepayers and shareholders would drive the incentives for efficient management. Apart from LRCA which recommended a sharing mechanism intervenors' consultants did as well, including Mark Drazen and Alan Rosenberg...

[15] Exhibit N-91, p. 27

> On fairness principles, the intervenors, the Board and their consultants have been denied the opportunity for a thorough analysis of this new revised FAM and the opportunity to pose information requests as to its implications.
>
> (Avon, Closing Submission, pp. 31-32)

[130] In closing submissions, CBRM, ECANS, HRM, MEUNSC, the NDP, the Province and SEB all objected to the approval of a FAM at this time. In its final argument, SEB states that:

> As noted above, SEB and other parties to this proceeding clearly believe that NSPI's fuel procurement strategy is simply not sufficiently well developed or managed to give ratepayers any comfort that a FAM could work to the benefit of the ratepayers at this time. The record is exceedingly clear in this regard, with statements from numerous experts – those of SEB and other parties – and SEB does not intend to reiterate those views here. Suffice it to say that, although not fundamentally opposed to the concept of a FAM, SEB does not believe the timing is right to impose such a mechanism upon NSPI's ratepayers. SEB does not believe that NSPI is yet fully sophisticated enough in fuel procurement, particularly Atlantic seaborne coal procurement, and it does not believe that NSPI has a proper complement of fuel expertise in-house. Furthermore, it has continuing concerns with the significant number and value of fuel transactions which occur with Emera affiliates. Until ratepayers have a much higher comfort level on these issues, SEB does not believe the Board should approve the adoption of a FAM.
>
> (SEB, Redacted Final Argument, p. 19)

4.3.3 Findings

[131] The Board shares the views of the intervenors with respect to the FAM proposed by NSPI. The Board recognizes that FAMs exist in many other jurisdictions and can, potentially, be a positive and useful regulatory tool. However, in view of the Board's findings with respect to imprudence and inadequacies in NSPI's fuel procurement practices, it would be quite inappropriate to approve a FAM at this time. The Board does not believe it is in the public interest to transfer the risk of fuel price volatility to ratepayers when NSPI's ability to achieve the best possible fuel price is in question.

[132] Further, the Board is of the view that transferring such risk from shareholders to ratepayers could diminish the incentive for NSPI to quickly and thoroughly improve its fuel procurement process. This is particularly the case since the FAM proposed by NSPI would transfer 100% of the risk to ratepayers. Accordingly, the Board rejects the proposed FAM. Further, in view of the Board's concerns in this area, should NSPI apply for approval of a FAM in future, the Board will order an independent audit of NSPI's overall progress and performance with respect to the necessary fuel procurement improvements. This audit would include, as recommended by Liberty, "... a more detailed examination..." of fuel and energy transactions and relationships with affiliates and would form part of the evidence the Board would consider in any future FAM application.[16]

[16]Exhibit N-135, p. 3

5.0 FINANCE

5.1 Return on Equity

5.1.1 Submissions - NSPI

[133] NSPI's expert witness concerning the issue of rate of return on common equity was Dr. Roger Morin, Professor of Finance at Georgia State University.

[134] In determining his recommended return on equity ("ROE"), Dr. Morin reviewed current market conditions and performed several risk premium studies. He indicated that he relied principally on the Capital Asset Pricing Model (CAPM), as well as the Risk Premium and the Discounted Cash Flow (DCF) methodologies in order to estimate a fair and reasonable ROE for NSPI. He examined the risk premiums allowed by regulators in North America and applied the DCF model to U.S. electric utilities. He also stated that he applied the DCF model to U.S. vertically integrated utilities and to natural gas distribution utilities to supplement the risk premium estimates. He indicated that he used the Comparable Earnings test as a supplementary check on his recommendations.[17]

[135] Based on the results of his risk premium studies, Dr. Morin determined that the risk premium range is 4.5% to 5.5%, with a midpoint of 5.0%. He then determined that the forecast risk-free rate of return is 5.7%. Adding the forecast risk-free rate of return to the risk premium range of 4.5% to 5.5%, Dr. Morin arrived at a ROE range of 10.2% to

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[17]Exhibit N-3, p. 14

11.2%, with a midpoint of 10.7%. He pointed out that his recommended ROE range of 10.2% to 11.2% is predicated on a common equity capital ratio of 37.5%.[18]

[136] In his direct evidence, Dr. Morin stated that:

> Based on the results of various methodologies, I recommend the adoption of a rate of return on common equity ("ROE") in the range of 10.2% - 11.2% with a midpoint of 10.7% for ratemaking purposes in 2005. A rate of return in this range is required in order to (i) attract capital on reasonable terms, (ii) maintain financial integrity, (iii) be commensurate with returns on comparable risk investments, and (iv) act as an incentive device for cost effectiveness and productivity gains. My ROE recommendation is derived from cost of capital studies that I performed using the financial models available to me and from the application of my professional judgment to the results obtained in light of NSPI's long-term investment risks and economic environment....My recommendation is predicated on the adoption of the Company's capital structure consisting of 37.5% common equity capital and the adoption of the Company's proposed fuel adjustment clause.
>
> (Exhibit N-3, Appendix G, p. 5)

[137] While NSPI recognizes and supports Dr. Morin's recommendation as appropriate, it nevertheless adopted an ROE of 10.2% for ratemaking purposes instead of the 10.7% recommended by Dr. Morin. NSPI stated its reason for doing so as follows:

> The Company supports his recommendations as being appropriate but in consideration of minimizing the impact on customer rates, the Company has based this Rate Application on an ROE of 10.2 percent for ratemaking purposes, which is the lower end of Dr. Morin's recommended range.
>
> (Exhibit N-1, p. 70)

[138] Dr. Morin clarified, in response to IR-55 from the Province (Exhibit N-27), that if a FAM is not approved and the common equity ratio remains at 37.5%, his recommended range would change to 10.70% to 11.70%, with the midpoint of 11.20% being used for ratemaking purposes. On cross-examination by Counsel for SEB, he stated:

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[18] Exhibit N-3, p. 71

Q. So, your testimony is that without a FAM your recommendation is 11.2 in a range of 10.7 to 11.7?

A. Yes, and I suspect a company would utilize 10.7, or the low end for rate-setting purposes

(Transcript, Nov. 18/04, pp. 587-588)

Mr. Tedesco indicated, during his cross-examination by Board Counsel, that without a FAM NSPI believes an appropriate return on equity would be 11.2%.

[139] The Board, in its rate decision of October 23, 2002, established an earning range of 9.90% to 10.40%, with the return on equity set at 10.15% for ratemaking purposes. NSPI responded to the suggestion of a number of intervenors that there has been no material change in NSPI's risk since the last hearing:

> Several intervenors have suggested through cross examination that NSPI's risk profile is no greater than it was in 2002, and some have even suggested that it has a lower risk profile, in support of their claims that NSPI does not require a higher ROE than that granted in 2002. The arguments for a lower risk profile stem from the fact that NSPI's financial risk has decreased since 2002 as a result of improvements the Company has made in its capital structure....
>
> Those intervenors who have suggested the ROE should be reduced because of the stronger financial profile have overlooked the fact that **this improvement was needed to maintain the Company's existing rating, not improve it....**
>
> ... Throughout this hearing, NSPI has provided evidence of the increased business risk since 2002:
>
> 1. Taxes have tripled and increased by $79 million since 2002.
> 2. Fuel prices are higher and more volatile now than in 2002.
> 3. The electricity sector throughout North America is viewed as more risky. Downgrades, escalating emphasis on environmental concerns, and deregulation have all changed the risk perception of the industry. NSPI is not immune to the overall perception of the industry.
> 4. Since 2002, Standard and Poor's have downgraded 14 Canadian electric utilities. In all cases, the reasons cited for the downgrades were increased business risk.
>
> In order to manage the risk profile of NSPI to reduce upward pressure on customer rates while balancing the requirements of the investment community, NSPI is proposing that a Fuel Adjustment Mechanism be introduced. The implementation of such a mechanism would reduce investors' overall risk perception of NSPI, enabling the Company's rates to incorporate a lower return on equity and therefore a lower cost to consumers.
>
> (NSPI, Closing Argument, pp. 10-12, emphasis in original)

5.1.2 Submissions - Intervenors

[140] Michael P. Gorman, a principal at Brubaker & Associates, Inc., appeared as an expert witness on behalf of SEB. Mr. Gorman indicated in his direct evidence that he used several financial models in order to estimate NSPI's cost of common equity.[19] They were: the constant growth discounted cash flow model (DCF); the risk premium model; and a capital asset pricing model (CAPM). He applied these models to a group of publicly traded utilities which he determined to proxy the investment risk of NSPI.

[141] Mr. Gorman stated that:

> Based on my analyses, I estimate an appropriate return on common equity for NSPI to be in the range of 9.1% to 10.1%, with a mid-point estimate of 9.6%. The high end of my estimated range is based on my CAPM analyses, and the bottom of my range is based on my DCF analysis.
>
> (Exhibit N–69, p. 17)

He indicated that:

> My recommended 9.6% common equity return does not include a possible management performance penalty as discussed by Dr. Alan Rosenberg. My proposed return on common equity for NSPI presents fair compensation based on today's market costs, and reflects the reduction in financial risk created by NSPI's increase of its common equity ratio in the capital structure NSPI proposes for setting rates. If the Nova Scotia Utility and Review Board (Board) adopts a fuel adjustment mechanism (FAM), it should reduce NSPI's authorized equity return by 0.50% to 0.25% below my recommended 9.6% common equity return to capture the reduced investment risk, created by implementation of a FAM.
>
> (Exhibit N-69, p. 2)

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[19]Exhibit N-69, p. 5

[142] Mr. Gorman also stated that his recommended return on common equity is reasonable because it produces adequate pre-tax earnings coverage of debt interest expense to support NSPI's current bond rating.

[143] Billie S. LaConte gave expert evidence on behalf of Avon. She is a consultant in the field of public utility economics and regulation, and is a member of Drazen Consulting Group, Inc.

[144] Her recommended ROE was determined by using the Equity Risk Premium (ERP) Method. The Equity Risk Premium is the extra return (premium) that the stock market requires over the risk free rate of return in order to compensate for market risk. The Equity Risk Premium was determined by using the Capital Asset Pricing Model (CAPM). The range which she recommends for a return on common equity is 8.70% to 9.30%.[20]

[145] Ms. LaConte testified that:

> I recommend the Board set a rate of return on equity for NSPI in the range of 8.7 to 9.3 percent. I base my recommendation on an analysis using the capital asset pricing model. With the fuel adjustment mechanism, I believe the return on equity should be set at the low end of my recommended range, 8.7 percent. Without a fuel adjustment mechanism, the Board should set the return on equity at 9.3 percent. If the Board wishes to allow a band width, then the authorized return should represent the mid-point of that band width with an equal probability [profitability] of NSPI earning above or below the authorized return.
>
> (Transcript, Nov. 19/04, pp. 889-890)

[146] In its reply submission, Avon states:

> Avon Valley et al, in its closing submissions urged that an appropriate ROE for NSPI was in the range of 9.3% - 9.6%, without a FAM. To clarify, it is recommended that the midpoint of NSPI's allowed ROE be set at some point between 9.3% and 9.6% in accordance with the

[20]Exhibit N-92, p. 3

> recommendations of Mr. Rothschild, Mr. Gorman and Ms. LaConte. Thereafter, the Board should permit a range of 25 basis points on either side of its allowed ROE.
>
> (Avon, Reply Submission, pp. 7-8)

[147] James A. Rothschild, President of Rothschild Financial Consulting, appeared as an expert witness for Board Counsel. In his direct evidence, Mr. Rothschild states that he determined the appropriate cost of equity by applying the Discounted Cash Flow (DCF) and Risk Premium/CAPM methods to the two groups of companies selected by Dr. Morin, NSPI's financial witness. Mr. Rothschild indicated that he applied two different versions of the DCF method and two different versions of the Risk Premium/CAPM method. He stated:

> ... Based upon the analyses I conducted, I find that the cost of equity to NSPI is 9.50% which is the midpoint of a 9.25% to 9.75% range and is applicable to a capital structure containing 37.50% common equity.
>
> (Exhibit N-133, p. 15)

[148] Mr. Rothschild also commented:

> ... The capital structure I have recommended is equal to the capital structure requested by the Company. This 37.50% common equity ratio is higher than the 35% allowed to NSPI in its last case, but is within the 40% ceiling that the UARB found acceptable in the last case and is reflective of the actual capital structure being used both by NSPI and its parent, Emera
>
> (Exhibit N-133, p. 6)

[149] According to Mr. Rothschild, he is recommending a reduction in the 10.15% cost of equity allowed in the 2002 rate case to 9.50% as a result of a decline in interest rates, and a reduced financial risk associated with NSPI's higher common equity ratio. He added that both of these changes have occurred since NSPI's last rate case.

[150] With respect to the proposed FAM, Mr. Rothschild stated that if a FAM were approved by the Board, his overall cost of capital recommendation would be reduced. This

is because the reduced risk of volatility in expenses resulting from a FAM would allow NSPI to use a smaller common equity ratio in its capital structure.

[151] Mr. Rothschild contrasted his recommended cost of equity of 9.50%, being the midpoint of a 9.25% to 9.75% range, with the cost of equity requested by NSPI of 10.20% and a range recommended by Dr. Morin of 10.2% to 11.2%.[21]

[152] The recommended ranges and the recommended ROE's of the various financial witnesses are set out in HRM's final submissions as follows:

Witness	**ROE Range**	**ROE with FAM**	**ROE w/o FAM**
Current NSPI ROE	*9.9%[9.75%] - 10.4%*	*N/A*	*9.9%[9.75%] - 10.4%*
Proposed -Mr. Rothschild	9.25%-9.75%	Not Provided	9.50%
Proposed -Mr. Gorman	9.10%- 10.10%	9.10%-9.35%	9.60%
Proposed - Ms. LaConte	8.70%-9.30%	8.70%	9.30%
NSPI (Dr. Morin)	10.20-11.20%	10.20%-11.20%	10.70%-11.70%

(HRM, Final Submission, p. 5)

5.1.3 Findings

[153] The Board has carefully considered the evidence of the experts on this issue. As noted earlier in this decision, the Board has not approved a FAM at the present time. Accordingly, the appropriate ROE has been determined on this basis.

[21] Exhibit N-33, p. 15

[154] The Board believes that an ROE of 9.50% to 9.60%, as recommended by Mr. Rothschild and Mr. Gorman respectively, fairly represents an appropriate ROE. The ROE of 11.2%, as recommended by Dr. Morin, is, in the opinion the Board, too high given the current economic climate. At the same time, the Board believes that the ROE of 9.30% which was recommended by Ms. LaConte is somewhat on the low side. Accordingly, the Board approves a ROE at 9.55% for the purpose of setting rates. The earnings range is set at 9.30% to 9.80%.

[155] It was pointed out during the hearing that, generally, other utilities calculate the rate of return using the rate base method, and there was a consensus among the intervenors that NSPI should change its method of calculating the rate of return.

[156] In its reply to closing arguments, NSPI states that:

> Some intervenors have recommended that the UARB set rates based on a return on rate base versus a return on the equity portion of total capitalization. NSPI determined its 2005 revenue requirement in its Rate Application based on the methodology that the UARB has used in previous decisions. NSPI has no particular objection to moving to a return on rate base provided the definition of rate base includes all capital invested for the benefit of rate payers.
>
> In theory the two approaches should arrive at the same revenue requirement. This was confirmed by Dr. Morin and Mr. Selecky. NSPI's Rebuttal Evidence shows that by employing the return on rate base approach that Mr. Selecky has proposed, the total capitalization and rate base are identical and the revenue requirement would be unchanged. The Rebuttal Evidence also illustrates that suggestions that NSPI is earning on non-regulated assets or equity are unfounded.
>
> (NSPI, Reply to Closing Arguments, p. 26)

[157] In its 2002 rate decision, the Board stated:

> ... This Board, in prior rate decisions, has based the revenue requirement for the test year on an allowed return on equity. The Board's focus has been a return on equity, and not return on rate base. Once the rate of return on common equity is determined, it is possible to calculate the return on average rate base.
>
> (Board Decision, Oct. 23/02, P-875, p. 79)

[158] In view of the comments expressed at the hearing, the Board believes it is appropriate to approve a change to NSPI's long-standing practice in this regard and directs that NSPI use a return on rate base methodology for the next rate application. Further, NSPI should file at that time all necessary information and explanations necessary to enable the Board and intervenors to clearly understand the basis of NSPI's calculations. NSPI should also reconcile its calculations of return on rate base to calculations using the return on equity methodology. It is not necessary, nor is there sufficient evidence on this point, in the Board's view, to determine in this proceeding if NSPI is correct in its suggestion that the revenue requirement should not be impacted by this change.

[159] The Board further directs NSPI, as part of the required Compliance Filing, to recalculate the return on average rate base in Table 5 of Exhibit N-2, taking into account the adjustments made to test year revenues and expenses as a result of this decision. Following a review, the Board will issue a final Order which, among other things, will approve the rate of return on average rate base.

5.2 Capital Structure

5.2.1 Submissions - NSPI

[160] In its direct evidence, NSPI indicates that the application is based on a common equity ratio of 37.5%. It refers to the Board's 2002 decision which states that:

> The Board directs the common equity level of NSPI remain at 35 percent for rate-making purposes. The Board would indicate that it has no objection to NSPI increasing its actual equity ratio in the future to 40%. However at any future rate hearing, the Board will determine what equity ratio is appropriate for rate-making

> purposes at that time, among other things the Board will consider the level of equity in Emera.
>
> Emera has a target capital structure common equity component of 40 – 45 percent. Emera Inc. expects to be at the low end of that range in 2005.
>
> (Exhibit N-1, p. 68)

In its closing argument, NSPI confirms that Emera's target capital structure for common equity is 40% to 45%, and that it expects to be at the low end of that range in 2005. It also states:

> There are several issues on which the ROE witnesses in this hearing agreed:
>
> - NSPI's requested common equity of 37.5% is reasonable considering the actions taken by bond rating agencies after the last decision.
>
> (NSPI, Closing Argument, p. 8)

5.2.2 Submissions - Intervenors

[161] SEB does not object to NSPI's contention that it should have a common equity component of 37.5%. In its closing submission, SEB states:

> SEB does not take issue with NSPI's position that it should have a deemed regulatory capital structure including 37.5% common equity, as long as this is actually supported by the common equity in the regulated business. However, as described in more detail below, SEB believes this increase in NSPI's common equity weighting must be considered in reviewing NSPI's risk profile for the purpose of determining an appropriate return on equity.
>
> (SEB, Closing Submission, p. 23)

[162] Avon, in its closing submission, states:

> Increasing the allowed equity component from 35% to 37.5% without changing the return on equity ("ROE") rate results in an increase in the required revenue of approximately $7.2 million for the test year 2005. If NSPI is also permitted to increase its allowed ROE to 10.20% as sought, the increased revenue requirement is $8.1 million.
>
> It is observed that none of the intervenors or experts presented direct evidence opposing NSPI's request to increase its common equity component to 37.5%. Indeed, the consensus seems to be that it is merited to support NSPI's bond rating.
>
> The import of this increase in common equity thickness, which comes at a higher cost to ratepayers, is that it reduces the financial risk of NSPI and, all other things being equal, should reduce NSPI's appropriate return on equity.

> In its 2002 decision, the Board stated that it had no objection to NSPI increasing its equity ratio in future (above the allowed 35% for rate making purposes) however, the Board wished to consider the level of equity in Emera. As is evident from the documents on file, Emera has a target capital structure common equity component of 40-45% and Emera expects to be at the low end of that range in 2005. This would suggest that the time is appropriate to allow NSPI's common equity to increase to 37.5%, with an appropriate recognition of the correlative reduction in risk and return on equity.
>
> (Avon, Closing Submission, p. 7)

[163] The Province also supports an increase in NSPI's common equity ratio to 37.5% for ratemaking purposes. It comments:

> No evidence has been filed opposing NSPI's request for a common equity component of 37.5%. NSPI stated that steps taken to increase its actual common equity in December 2002 to approximately 37.5% assisted in maintaining its current bond ratings. Those ratings have remained constant since December 2001. The Province supports NSPI's application to have common equity increased to 37.5% for ratemaking purposes.
>
> The Province also supports continued growth toward 40% common equity in NSPI taking into account that any further increase in common equity must result in a lower return on equity. Any further increase in the common equity for ratemaking purposes would require the approval of the Board as stated in the 2002 Rate Case Decision, and any further increase in common equity should not add any increase to NSPI's revenue requirement.
>
> (Province, Closing Submission, p. 36)

[164] With respect to future increases in the common equity ratio, the Province indicated that, while it supported continued growth towards 40% common equity, any further increase in the common equity ratio must result in a lower ROE.

[165] ECANS indicates that, while it has no issues in principle with a 37.5% common equity ratio, it cannot support the proposal in view of the significant impact the increase would have on ratepayers.[22]

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[22]ECANS, Final Brief, p. 17

5.2.3 Findings

[166] The Board has considered the evidence concerning this matter and approves the proposed increase in the common equity ratio for ratemaking purposes from 35% to 37.5%. The Board is satisfied that the strengthening of the balance sheet in this way is desirable in the current economic climate. The Board notes that the majority of intervenors appear to be in favour of the proposed increase in the common equity thickness.

[167] In its October 23, 2002 rate decision, the Board stated:

> ... The Board understands the benefits which could flow from an increase in the common equity ratio. However, the Board also accepts Mr. Rothschild's view that without a corresponding increase in the common equity ratio of NSPI's parent company, Emera, there will likely be no overall benefit accruing from an increase in the common equity level of NSPI. ...
>
> (Board Decision, Oct. 23/02, P-875, pp. 72-73)

[168] The Board continues to be of the view that this is the case. With respect to the common equity component of NSPI's parent company, Emera, the Board notes that as at December 31, 2003 Emera had a common equity ratio of 38.0%, and in NSPI's response to the Province's IR-34 (Exhibit N-27), Emera was projected to have a common equity ratio of 39.1% as at December 31, 2004, which is not expected to change significantly in 2005.

[169] On this basis, the Board approves the increase in NSPI's common equity ratio to 37.5% for ratemaking purposes.

6.0 TAXES

6.1 Section 21 Costs and Amortization

6.1.1 Submissions - NSPI

[170] As noted earlier, on June 11, 2004, the Supreme Court of Canada ("SCC") heard and dismissed an appeal by NSPI relating to deductions claimed under **s. 21** of the **Income Tax Act** between 1998 and 2002. On June 23, 2004, NSPI substantially revised its application to recover the costs it now faces as a result of the SCC decision. NSPI has requested Board approval to recover approximately $150 million in additional tax and interest expenses that have not, to date, been included in NSPI's costs which are used to calculate rates charged to customers.

[171] NSPI sets out its position as follows:

> This evidence revises the May 28, 2004 Rate Application to account for the Supreme Court of Canada decision of June 11, 2004. The Court dismissed NSPI's arguments in favour of deductions under Section 21 of the Income Tax Act. Under law, these taxes are a cost of service recoverable by the Company in rates.
>
> The Section 21 elections postponed a substantial increase in revenue required to be collected through rates between 1998 and 2002. A successful court case would have secured this original benefit to customers, as well as substantial additional benefits in subsequent years for a total benefit to customers estimated at more than a quarter of a billion dollars.
>
> The actions taken by NSPI at each step in the process were wholly reasonable and supported by expert opinion, the favourable ruling of the Tax Court of Canada, and the sheer size of the potential benefit to customers. At all times, the Company took steps to minimize costs to customers.
>
> The Supreme Court of Canada decision has the unfortunate effect of further increasing tax costs.
>
> The Court's ruling cannot be appealed. Therefore, the principal and interest that the Company deposited with the CRA must now be recovered in rates.
>
> In light of the decision of the SCC and the foregoing evidence, NSPI seeks an order from the Board:
>
> a. Amortizing the Section 21 deferral over a seven-year period beginning in 2005, and

> b. Providing for the recovery of these amortized costs through the customer rates described in this revision to the original Rate Application.
>
> (Exhibit N-3, Appendix O, p. 32)

[172] NSPI proposes to expense the $150 million by amortizing $21.4 million per year for the years 2005 through 2011.[23] The revised 2005 revenue requirement is $1,072.9 million, $32.7 million more than in the original application. The $32.7 million is as a result of the **s. 21** decision and related tax impacts. Since below-the-line ("BTL") rates are based principally on fuel costs rather than tax costs, these customers are impacted by an additional $1.8 million. Above-the-line ("ATL") customers, whose rates are based on a broader range of expenses, face a revenue requirement increase of $30.9 million which moves the average increase in rates for ATL customers from 8.6% in the May, 2004 filing to 12.4% in the June, 2004 revised filing.[24]

[173] NSPI takes the position that tax costs and related expenses are legitimately recoverable utility costs which are, for the most part, beyond its control. It suggests that there is no question that its increased costs as a result of the SCC decision should be included in the Company's revenue requirement and be passed on to customers through rates. The only issue NSPI believes is left to be determined is the appropriate length of time over which these costs will be recovered.

[174] The principal issues raised by intervenors relate to NSPI's decision to pay 50% rather than 100% of the tax costs during the initial stage of the appeal process and

[23] Appendix O, p. 10

[24] Appendix O, p. 12

the appropriate amortization period and methodology to be used. With respect to the timing issue, the balance of the outstanding tax cost was paid by NSPI following the unfavourable ruling by the Federal Court of Appeal on January 24, 2003.[25]

[175] Along with Gordon Lawlor, Director of Finance at Emera (who also oversees taxation at NSPI) and Ron Smith, former Senior Vice President and Chief Financial Officer for Emera, Richard Daw, a partner with Deloitte Touche in St. John's, Newfoundland, appeared on NSPI's tax panel at the rate hearing. Mr. Daw described his work for NSPI as follows:

> We were engaged to do three things. One, to look at the provision which was in the December 31st, 2005 financial projections for the purposes of this hearing. Second, we were to review the aspects and their behaviour towards the Section 21 case, and particular to look at whether it was reasonable that they paid the taxes and interest when they paid it. And third, we were to look at the management of their tax function in general to comment on it. And then we were asked to attend and prepare for the Tax Technical Conference, and finally to appear here.
>
> (Transcript, Nov 25/04, p. 1860)

[176] In Mr. Daw's direct evidence, filed prior to the SCC's decision, he outlined the procedures followed in assessing the **s. 21** tax issue:

> As part of a review of its tax position in 1998, Nova Scotia Power amended its 1992 income tax return by increasing, by over $900 million, the capital cost on assets acquired from Nova Scotia Power Corporation. This represented interest incurred by the crown corporation on assets it constructed. Capitalizing the interest is pursuant to Section 21 of the Income Tax Act.
>
> This permitted Nova Scotia Power Inc. to claim additional tax depreciation (capital cost allowance) on this interest which ultimately resulted in taxable income being lower than accounting income. Since the Company pays tax on a cash basis, these claims for additional tax depreciation reduced the income tax provision substantially below the statutory rate.
>
> This position was challenged by CRA which reassessed the Company's tax returns to disallow the claims for additional tax depreciation. The Company successfully appealed these reassessments to the Tax Court of Canada, but that decision was overturned by the Federal Court of Appeal. The Supreme Court of Canada has granted leave to appeal, with submissions expected in June 2004.

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[25] Exhibit N-6, Appendix O, p. 5

> Nova Scotia Power has adjusted its 2003 income tax return and projected its 2004 and 2005 income tax provisions as though the Federal Court of Appeal decision was upheld by the Supreme Court of Canada. In other words, the carry-forward balances at December 2002 have been reduced by the interest that had been capitalized.
>
> It is our considered opinion that this is a reasonable approach to forecasting the Company's 2005 income tax provision.
>
> As a large corporation, Nova Scotia Power is required to pay one-half of income tax assessments that are being disputed. Given the unfavourable ruling of the Federal Court of Appeal, the Company decided to pay all the income taxes reassessed in this matter to date - $49 million. As well, the Company calculated the balance of related reassessments, in advance of such reassessments being issued, up to the December 2002 year. This estimate has also been paid - $108 million. This total of $157 million, minus various tax credits and adjustments of $13 million, is now recorded as deferred expense on the balance sheet.
>
> These payments were made to limit the amount of high rate non-deductible interest charged by the CRA on unpaid amounts in the event of an unfavourable ruling by the Supreme Court of Canada.
>
> If the Supreme Court of Canada overturns the Federal Court of Appeal decision, Nova Scotia Power will recover all of its funds.
>
> We have reviewed the Company's working papers and rationale and believe that Nova Scotia Power Inc. made a reasonable decision to pay these amounts.
>
> (Exhibit N-2, Appendix B, pp. 5-6)

[177] In the addition to Mr. Daw's evidence, which is dated June 18, 2004, he stated:

> On June 11, 2004, the Supreme Court of Canada dismissed Nova Scotia Power's appeal from the Federal Court of Appeal decision to disallow the Company's claims for extra capital cost allowance pursuant to Section 21 of the Income Tax Act (Canada).
>
> Since the Company's 2005 forecasted income tax provision was already prepared as though the Federal Court of Appeal decision was upheld by the Supreme Court of Canada, it is still our opinion that the tax provision has been properly calculated and that it was reasonable to calculate the provision on that basis.
>
> We continue to believe that Nova Scotia Power made a reasonable decision to pay all the income taxes reassessed in the Section 21 Income Tax Case to date, in addition to all the estimated taxes in advance of reassessments being issued. We understand that the Company has amended its application to request rate adjustments to recover these paid amounts over a period of seven years. These amounts would be in addition to the tax provisions originally calculated.
>
> We continue to believe that the management of Nova Scotia Power has been prudent in managing its income tax expense.
>
> (Exhibit N-2, Appendix B, Addition, p. 1)

[178] In his opening statement at the hearing, Mr. Lawlor said:

> ... Our Section 21 strategy has been accepted -- either explicitly or implicitly -- as being in the overall best interest of customers. We feel there are just a few key issues raised in the intervenor evidence that will require the Board's consideration. The length of the amortization of the Section 21 costs is an issue. The Board must strike a balance between minimizing the effect of the recovery through rates, while ensuring the customers who benefitted from the deductions are largely the same customers to share the cost. One intervenor argues that NSPI should not recover all of the twenty million in interest expense associated with the Section 21 deductions. This position requires a special type of hindsight about the case and ignores the fact that preemptively remitting funds to the Canada Revenue Agency would cause the company to incur significant costs that could not be recovered. For the reasons we have put forth in our evidence, we believe we have clearly demonstrated that we acted responsibly, promptly and in the best interests of customers in scheduling our payments to avoid unnecessary expense. Another question was raised about whether the Section 21 case should somehow be used as a reason to reduce our rate of return -- retroactively. In our view, this would be wrong. The actions the company undertook with regard to Section 21 were conducted 'in the light of day' with the support from the Province. These are the main material questions raised. Otherwise, the dramatic increase in tax expense and need to reflect these costs in rates remains very much the elephant in the room in this rate hearing. As detailed in our direct evidence, since 2002, when electricity rates were last reviewed by the UARB, Nova Scotia Power's overall tax bill has more than tripled to a hundred and thirteen million annually, an increase of seventy-nine million dollars ($79,000,000). This is primarily a result of higher corporate income taxes and the doubling of the grants in lieu of property taxes. To date, the company has been able to shield customers from the full impact of these taxes, but in 2005, the picture is different. In addition to these increased tax costs, the Supreme Court of Canada decision in the Section 21 case disallowed deductions used to keep rates lower between 1998 and 2002. That decision ended a seven-year effort by Nova Scotia Power in three different courts to save customers ultimately more than a quarter billion dollars in taxes. It cannot be appealed. As a result, NSPI now seeks to recover these costs through customer rates...
>
> (Transcript, Nov 25/04, pp. 1863-1865)

[179] Under questioning by the Board, Mr. Daw explained his disagreement with the suggestion that NSPI was imprudent in its manner of paying the taxes:

> Q. Thank you. Mr. Daw, in - - what do you make of the conclusions by Mr. Ewens that - - as appearing on page 11 of his report which Mr. Outhouse referred to a little earlier - - its N-61, page 11, where at the top he basically says:
>
> > "Accordingly, in my opinion, NSPI failed to act prudently by not paying the 100 percent and also not paying the total additional business when NSPI found out that the disallowances were going to be made."
>
> Do you agree with that comment?
>
> A. (Daw) No, I do not.
>
> Q. Would you explain why?

A. (Daw) When asked to determine whether they were reasonable to make the payments when they did, which was before the Supreme Court decision, which was actually just after the time the Federal Court of Appeal turned down the Tax Court decision, I had to put myself in their position at the time they made the decision using the information they had available at the time. And at the time, they had received one reassessment, had paid it, had received another, had paid 50 percent, and that was within a few months of them expecting the Tax Court of Canada decision. And up till that time they had not received any other reassessments for any other years. In January, 2002 when they received the Tax Court of Canada decision, which was favourable to them, they felt it was unnecessary to pay any more at the time, and I agree with that. Secondly, not every company pays more than the required amount of the taxes and reassessments at the time, as noticed in Newfoundland Power's case. And finally, again, you must recall that they still did not receive any other reassessments for any other years for either losses carried forward from the Section 21 depreciation claims or for the actual capital cost allowance claims in the current years as well. When the Federal Court of Appeal actually went against them, then they determined that they would pay all the taxes, not only the balance of those that had actually been reassessed, but to determine the amounts that had yet to be reassessed right up to 2002. I thought that -- if I was in those circumstances that would have been a reasonable approach to make. And from a business decision standpoint, which I checked, it appeared that it probably wouldn't have cost that much more to do it that way anyway. So I did not agree then with Mr. Ewens' assumption or assertion that they were not being prudent by not paying all the taxes in advance.

Q. So when the Federal Court went against them, that's when they paid the ---

A. (Daw) Within a very short period of that date, yes.

Q. And it's your view, then, that once they received a favourable ruling from the Tax Court that they had every expectation to -- that they were going to continue or that they had a favourable -- a reasonable expectation of getting a favourable verdict out of the next -- out of the Federal Court. And on that basis, it wasn't necessary or it ---

A. (Daw) In my ---

Q. --- was a reasonable decision, in your view, not to pay the balance.

A. (Daw) In my view it was.

Q. What about Mr. Ewens' comment that generally utilities pay the total amount owing as opposed to the 50 percent because of the unique nature of the entity?

A. (Daw) Not all entities pay more than the 50 percent. Again, look at Newfoundland Power's example. My view is that if they felt confident in the decision, if they felt confident in the case as given the advice that they'd had and given the Tax Court of Canada ruling, then it was reasonable to not pay any more than the required amount.

... and ...

Q. You used Newfoundland Hydro as an example of a situation where a regulated utility did not pay the full amount. Are there any other examples that you're aware of?

A. (Daw) The only example here that I used was actually Newfoundland Power.

Q. Newfoundland Power. Sorry. Because in Mr. Ewens' evidence it's -- he indicates that generally utilities do it a different way.

A. (Daw) It's my understanding that it was also on the basis, Madam Chair, if they felt confident in the result it wasn't always necessary to pay more than 50 percent.

(Transcript, Nov 25/04, pp. 1968-1972)

[180] In its Closing Argument, NSPI responded to allegations of imprudence in its actions with the Canadian Revenue Agency:

> ... The record shows that at every step NSPI proceeded carefully and only after considerable reflection. The cautious approach taken throughout the entire proceeding underscores NSPI's determination to act prudently.
>
> (NSPI, Closing Argument, p. 28)

[181] NSPI also responded to the suggestion of intervenors to exclude part of **s. 21** costs due to "excess earning" from 1998 to 2002:

> During cross-examination Mr. Selecky testified that he had no regulatory or accounting support for his position. NSPI asserts that his position is unprecedented and unsupportable.
>
> NSPI strongly disagrees with the recommendation of Mr. Selecky. Not only is there no precedent, but also such a recommendation would effectively cap NSPI's earnings at the low end of the ROE range. There would be no incentive to manage costs or undertake any initiatives for the benefit of ratepayers if there was any associated risk.
>
> (NSPI, Closing Argument, pp. 36-37)

[182] NSPI points out, in its Closing Argument, that extending the amortization period from seven to 10 years, using a levelized methodology as proposed by one of SEB's experts, does increase the total revenue requirement over the life of the amortization by approximately $35 million.[26]

[183] NSPI, in the SA, agreed to increase the proposed amortization period for the **s. 21** taxes from 7 years to 17 years, with a complete deferral of this expense in 2005. Under the SA, the recovery of the **s. 21** taxes would be accomplished by applying money currently in rates for amortization of defeasance and the Glace Bay generating station costs to **s. 21** taxes when those funds are no longer required. This method of amortization

[26] NSPI Closing Argument (Redacted), Dec. 13/04, p. 36

recovers the full $150 million over a period of seventeen years. The commencement year is 2005, with an amortization amount of zero, and the end year is 2021, with an amortization amount of $14.2 million.[27]

[184] In his opening statement on the SA, Mr. Tedesco remarked:

> ... Also regarding Section 21, this proposal is better for customers next year, is nearly equivalent to the original proposal on a net present value basis, and from a customer perspective, assuming the Company's rate of return, is actually better on a net present value basis. ...
>
> (Transcript, Jan 13, 2005, p. 3517)

6.1.2 Submissions - Intervenors

[185] Witnesses for SEB recommend reductions in the amount of the **s. 21** taxes that should be recovered from ratepayers. James T. Selecky of Brubaker & Associates, Inc., in his direct evidence, recommends that the **s. 21** taxes should be reduced by $20.2 million to reflect the difference between NSPI's earned ROE and the low end of its allowed return on equity from 1999 to 2002.[28] Both ECANS and Avon support Mr. Selecky's position in their closing submissions.[29]

[186] Douglas Ewens, Q.C., of McCarthy Tétrault, was also retained by SEB to provide an opinion on issues arising out of tax planning undertaken by NSPI and the resulting **s. 21** income tax litigation. In his direct evidence, Mr. Ewens states:

---

[27]Exhibit S-1, Table - **S.21** Treatment

[28]Exhibit N-68, pp. 22-25

[29]ECANS, Final Brief, p. 14
Avon, Closing Submission, pp. 42-44

Accordingly, in my opinion NSPI failed to act prudently by:

(a) having decided to pay on August 31, 2001 only 50%, rather than 100% of the tax reassessed by the Minister at the time of NSPI receiving the 2000 Reassessment and to defer payment of the remaining 50% of such tax until the time of the adverse decision of the Federal Court of Appeal; and

(b) not having also paid at the time of receiving the reassessment for its 1999 taxation year (i.e. April 26, 2001) the Additional 1999 and 2000 $40 million Tax Liability that NSPI knew it would be liable for (as described in paragraph 21 hereof) if the Attempted $995,260,716 NSPC Interest Capitalization issue were resolved against NSPI plus the portion of the Post-2000 $79 million Tax Liability that had accrued to April 26, 2001.

(Exhibit N-73, pp. 10-11)

[187] SEB, in its final argument, states that the Board should:

Disallow $20.8 million from NSPI's revenue requirement, on the basis of NSPI's imprudent decision to not pay the full amount of the Section 21 tax liability at the earliest time when it would have been entitled to pay such tax, and thus minimize or eliminate its risk of incurring non-deductible interest charges, compounding daily;

(SEB, Final Argument, p. 3)

[188] Avon made similar arguments for a disallowance based on an imprudent tax strategy:

It is respectfully submitted that this Board should disallow $21 million relating to the s. 21 strategy for reasons relating to imprudence. In the alternative, where NSPI's shareholders shared in the benefit of the tax strategy, the burden should also be shared on the used and useful principles. Furthermore, and in any event, the time period over which the tax payments should be depreciated should be set at 10 years, and levelized to lessen the rate impact.

(Avon, Closing Submission, p. 39)

[189] In his direct evidence, Mr. Selecky also recommends that the **s. 21** amortization period be extended to ten years and the annual amounts to be amortized be adjusted to produce a levelized revenue requirement over the amortization period.[30]

[190] A comparison of the NSPI seven year amortization period and Mr. Selecky's ten year levelized amortization period is shown below:

[30]Exhibit N-68, pp. 20-22

S. 21 AMORTIZATION PERIODS

Year	NSPI		J.T. SELECKY	
	Amortization	Revenue Requirement	Amortization	Revenue Requirement
1	$21.43	$48.81	$10.60	$32.54
2	$21.43	$46.43	$11.40	$32.56
3	$21.43	$44.06	$12.25	$32.59
4	$21.43	$41.69	$13.17	$32.61
5	$21.43	$39.31	$14.16	$32.63
6	$21.43	$36.94	$15.22	$32.66
7	$21.43	$34.56	$16.36	$32.69
8			$17.59	$32.72
9			$18.91	$32.75
10			$20.33	$32.79
TOTALS	$150.00	$291.80	$150.00	$326.54

(Summary of data from Exhibit N-68, Ex. JTS-2, page 1 of 2 and Ex. JTS-3)

[191] Avon supports the ten year levelized amortization period in its closing submission, as does ECANS.

[192] Board Counsel's witnesses on this issue were J. Patrick O'Neil, FCA, CMC, and Elaine Sibson, FCA, senior partners with PricewaterhouseCoopers ("PwC"). Ms. Sibson's direct evidence as to whether these tax costs should be included in the test year revenue states:

> The only amounts in question in this area relate to the non-deductible interest and the question of whether or not NSPI acted prudently with respect to the reassessment and the payment of the assessed taxes.
>
> This is clearly a matter of judgment. Assuming advice was given by other professional firms that the matter had a likelihood of succeeding, we are not in a position, at this time, to question their professional opinions.
>
> (Exhibit N-131, p. 14)

[193] Ms. Sibson elaborated on this question in her evidence at the hearing. In response to questions from the Board she states:

> Q. And do you have any opinion as to whether or not they acted prudently or imprudently? I know you did refer to this in your opening statement this morning, but I'd just like to discuss it with you.
>
> A. (Sibson) If you can bear with me for just one minute, I'll try to explain how I saw the sequence of events yesterday in terms of Mr. Daw and Mr. Ewens. For the last four years, I've served on the Executive of the Canadian Tax Foundation and in last year as Chair. And in that capacity -- the Canadian Tax Foundation is the body that represents all tax lawyers and all tax accountants in Canada. So in that capacity, I've had the ability to deal with both sides of the profession, and basically they look at things differently. A tax accountant will come at it from the point of view of a business decision first and foremost, where a tax lawyer will come at it from the point of view of matters of law and what is right and what is wrong. So in Mr. Daw's situation, he was looking at the sequence of events and the timing, and he was saying, you know, "Should you prepay tax when it's not assessed yet, considering the fact you don't get any interest on that money if it's prepaid and the decision is turned around." So from a business point of view, you probably would not necessarily pay it. On the other side, Mr. Ewens would look at it from the point of view were they right or wrong in the first instance in trying to claim the Section 21 almost billion dollars worth of write-offs. And he would look at the opinions of the other tax lawyers, and in my experience as well, they quite often differ in their opinions of whether they're going to be successful or not in the Tax Court. Me, as an accountant looking at the situation, and were they prudent, you'd also have to take into account the fact that it's a utility and you have to be much more prudent in a utility than you would be in a normal business decision. So I don't have the experience that Mr. Daw and Mr. Ewens have in dealing with utilities, although speaking with our Winnipeg partner who does have considerable experience, his position was that they should have at least paid the assessed taxes. But I think this is why you're getting conflicts of interest a little bit in what's prudent and what's not prudent.
>
> Q. So you don't have any view, in other words, as to whether or not they were prudent or imprudent.
>
> A. (Sibson) I guess my personal view would have been to pay the assessed taxes. From a business point of view, whether you pay the additional taxes or not, that's really a business decision based on all the factors that take place in the organization, the cost of capital, the borrowing cost and ---
>
> Q. So that's a judgement call, in your view.
>
> A. (Sibson) A judgement call. And the reason I didn't get into it significantly was because looking at it again as an accountant, the amount is not material relative to some of the other more significant items that I saw and put in my report.
>
> (Transcript, Nov. 26/04, pp. 2077-2080)

[194] In its Final Argument, SEB characterized the evidence of Ms. Sibson and Mr. Daw as follows:

> With the greatest respect to both Mr. Daw and Ms. Sibson, who commented on this issue under cross examination by Commissioner Morash, neither appeared to have addressed the actual issue at hand. The decision whether or not to prepay the tax is a

> business decision, but it is a business decision based on the perceived chances of success as determined by an assessment of the strength of one's legal case. In a utility setting, particularly where the utility intends to seek recovery of its interest costs in the event it is unsuccessful, the burden is greater than in a non-utility situation. It is not simply a question of whether a reasonable person in an unregulated business might or might not make a different business decision regarding the payment of taxes. It is a question of whether the utility fully considered the impact on its ratepayers, and acted appropriately. ...
>
> (SEB, Final Argument, p. 35)

6.1.3 Findings

[195] After a review of the evidence in this matter, the Board is not convinced that NSPI acted imprudently in its method of payment of the **s. 21** taxes. There is no question that, generally, taxes are a reasonable cost which utilities are expected to recover. **Section 21** taxes also fall into this category. The Board has also noted the calculations set out in Undertaking U-31 which reflects the cost differences between Mr. Ewen's suggested approach and the one chosen by NSPI. The amount differs depending on a number of factors, including the interest rate used, but the range is between $800,000 and $3.7 million.

[196] While Mr. Ewen's testimony is persuasive, the Board finds that there is not sufficient evidence to convince it that NSPI's handling of this matter was imprudent. There is some suggestion that a higher standard prevails in the case of a utility and Ms. Sibson made a comment along these lines, based on a discussion with her colleague in Winnipeg who has expertise in utility regulation. However, that individual was not at the hearing nor is there specific information on this subject. Accordingly, the Board is unable to conclude that the amount of **s. 21** taxes to be recovered should be reduced as recommended either by Mr. Ewens or Mr. Selecky.

[197] There was much discussion during the hearing on the amortization period which should be used for the **s. 21** tax costs and whether or not the amortization should be adjusted to produce a levelized revenue requirement. One of the principal factors to consider when determining how long a period of time is appropriate is that of intergenerational equity. This is a regulatory term which refers to the need to ensure fairness to customers over periods of time. Recovery of costs should be timed, to the extent reasonable, to ensure that customers who derive a benefit from an action by the utility are the same customers who eventually pay the costs associated with that activity.

[198] During his testimony at the SA hearing, Dr. Stutz answered questions from the Board on both these issues:

> Q. ... Mr. Selecky with respect to the Section 21 tax costs has suggested that they be amortized for 10 years rather than the company's suggested 7, and that the cost each of those years would be flat not increasing or decreasing. And the company has suggested 7 and talked about concerns about intergenerational inequity or the fact, I guess, that you ought to time the recovery of these things so that the people who got the benefit of them not being paid are also the people who end up having to pay for it. Do you have any concerns with respect to the 10-year suggestion as opposed to seven?
>
> A. I think it's within the realm of judgment. If Mr. Selecky had proposed 20 years I might have had a different answer, but intergenerational equity is a very important but vague concern, and I think a couple of years on either side of what the company has proposed would be well within the kind of judgment that the Board might exercise. To me personally the most interesting part of what Mr. Selecky had to say was the idea of amortizing things in a flat fashion. I must admit I must have been asleep at the switch but I didn't quite think about the return, I just thought about the amortization, and so the company's dividing it and recovering it in what looks like a flat fashion. I must have just been asleep as I say because I didn't think about the return, when you put the return in, you do get a declining recovery. Mr. Selecky's proposal operates more like a mortgage. So whether you choose 7 or 10, a matter for your judgment, I would make it flat in the way Mr. Selecky did.
>
> (Transcript, Dec. 3/04, pp. 3449-3450)

[199] The Board is mindful that an appropriate balance needs to be achieved in easing the impact of this increase in costs on ratepayers without extending the recovery period for such a long period of time that intergenerational equity is overly compromised.

The issue of determining appropriate amortization periods is not a precedent for the Board. The retirement of the Glace Bay generating station raised similar issues. The Board must balance what is a reasonable and fair amortization period with the interests of ratepayers and the avoidance of rate shock. In this case, the Board notes that Dr. Stutz has suggested that a 10 year amortization period, under these circumstances, would comply with the principle of intergenerational equity. In order to avoid a higher than acceptable rate increase the Board also believes that deferral of the recovery period is warranted.

[200] After considerable reflection, the Board finds that amortization of the **s. 21** taxes should be deferred for two years (2005 and 2006) and, commencing in 2007, amortization over an 8 year period should occur. The Board is satisfied that this approach is reasonable for ratepayers and NSPI, and complies with the regulatory principle of intergenerational equity. In addition, the Board agrees with Mr. Selecky's method of amortization in that a levelized revenue requirement over the 8 year period is appropriate. This approach will eliminate the $21.4 million amortization in the 2005 test year which, according to NSPI's evidence, will result in an actual reduction in NSPI's 2005 revenue requirement of approximately $32.7 million. The Board directs NSPI to include this reduction in its Compliance Filing.

7.0 OPERATING, MAINTENANCE AND GENERAL EXPENSES (OM&G)

7.1 Pension Expense

7.1.1 Submissions - NSPI

[201] In its pre-filed evidence, NSPI projected that its OM&G costs in the test year are essentially the same as they were in 2002, with the exception of pension costs. It stated:

> ... With the exception of pension expense increases, the Company's overall OM&G costs are essentially unchanged since 2002C. This has been achieved despite rising demands for power, more customers, and a projected rise in the consumer price index over this period of 6.8 percent
>
> (Exhibit N-1, p. 5)

[202] The projected pension expense for the test year of 2005 is $26 million, an increase of $19 million from the $7 million pension cost in 2002. NSPI explained the increase as follows:

> The increase reflects a general trend over the past few years that has been a major issue among many companies that sponsor defined benefit pension plans.
>
> NSPI's pension expense has increased since the last Rate Application as a result of the following:
>
> 1. Changes in actuarial assumptions as a result of ongoing review. In particular, the asset return assumption was recently changed to 7.5 percent in 2003 from 8.0 percent in 2002. The updated assumption better reflects the current economic environment, and is supported by the fact that it is the median assumption used by Canadian companies. Assumptions about retirement age have also been changed from 60.5 to 59, which better reflects our actual experience.
> 2. A decrease in the discount rate used to determine the present value of liabilities in the pension plan and the current service cost for each period. The discount rate is based on the yield on long-term corporate bonds. With the decline in bond yields the discount rate has fallen, increasing the current service cost portion of pension expense. ...
>
> (Exhibit N-1, pp. 53-54)

[203] NSPI reiterated the reason for the change in pension costs in its closing submission:

> **…** Almost all of the change (See SEB IR - 282) relates to changing actuarial assumptions for the discount rate and the asset return assumptions. These changes are the result of changes in the market and are outside the control of management.
>
> (NSPI, Closing Argument, p. 41)

[204] NSPI's projected pension expense is based on a discount rate of 5.75%, and a rate of return on assets of 7.50%. Greg Blunden, NSPI's General Manager of Finance, explained, in response to questions from David MacDougall, Counsel for SEB, that the actual discount rate would be not identified until early 2005:

> Q. I think -- Mr. Blunden, let's see if we can do it this way. And I don't know that I have the IR responses in front of me, so I apologize for that, because I didn't expect the answer the way you said it, but let me try and go through the questions and we'll see if we can deal with it this way. You will at the end of the year pick a discount rate. Correct
>
> A. (Blunden) That is correct, although it would most likely be early in January just for clarification purposes, yes.
>
> Q. Sure. Early in January. It's done after December 31?
>
> A. (Blunden) That would be correct.
>
> Q. But for the purposes of applying for rates you have to make an estimate of that, because you're putting a discount rate in your rates that will be different than the discount rate that will actually go into effect at the time you choose it because this rate hearing will have finished and you've made your forecast?
>
> A. (Blunden) Yes, that would be correct. We will not know the actual discount rate until early in January.
>
> (Transcript, Nov 26/04, pp. 2130-2131)

[205] During the hearing, NSPI's finance panel, including Zeda Redden, Treasurer for both NSPI and Emera, along with Mr. Blunden, outlined NSPI's position with regard to the increase in pension costs and indicated that NSPI uses the firm of Morneau Sobeco

as pension advisors. Paul Chang, a representative of that company, attended one of the technical conferences leading up to the rate hearing.[31]

[206] Mr. Blunden, responding to Counsel for SEB, made the following comments on the linkage between pension costs and discount rates and whether there is flexibility in discount rates:

> Q. And there is some flexibility around choosing discount rates?
>
> A. (Blunden) I would suggest there's very little sensitivity. We have a track record of picking bonds of a certain duration to tie into our pension liabilities. Our actuary will come at the end of the year or early in January and show us what those bond yields are. It is subject to an actuarial opinion, it is subject to review by our audit committee, it is subject to review by our auditors. Of all of the assumptions that we would make on a day-to-day basis from a management perspective, I would suggest that's one of the ones that we have the least amount of variability on.
>
> Q. Well, I guess I'll stick with that a bit, though, because at the technical conference I believe Mr. Chang said that there would be a range, he would look at numbers within a range, there wouldn't be a set number, and I believe again Mr. O'Neil stated a range and I believe in all the materials, even the IR response that we just referenced, there is a range. So, there's certainly flexibility of up to 50 basis points on which your actuary, I'm certain, said, you know, he was not driven by a specific number but would look within a reasonable range.
>
> A. (Blunden) I would expect the ranges that people -- that you're seeing are probably more related to -- when you compare it to comparable companies, are more related to the profile of their obligations as opposed to any discretion. Again, I would disagree that we have any discretion on that. Where we do have a little more discretion is around our expected return on plant assets.
>
> Q. So, you're saying there's no flexibility from the actuary's point of view on your discount rate?
>
> A. (Blunden) I would suggest that we have very minimal.
>
> Q. Were you at the finance technical conference?
>
> A. (Blunden) I was.
>
> Q. Was that your recollection of what Mr. Chang said at the finance technical conference?
>
> A. (Blunden) Yes, it was.
>
> (Transcript, Nov. 26/04, pp. 2128-2129)

[207] In the SA, NSPI agreed to reduce its pension expense by increasing the discount rate from 5.75% to 6.0%. While Exhibit S-1 does not explicitly state the reduction

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[31] Transcript, Nov. 26/04, p. 2120

in pension expense which would occur due to the increase in the discount rate from 5.75% to 6.00%, NSPI, in an earlier response to SEB IR-233 (Exhibit N-28), stated that a change in the discount rate from 5.75% to 6.00% would reduce the pension expense by $2.7 million.

[208] Under questioning by Counsel for Avon during the SA portion of the hearing, Mr. Tedesco made the following comment:

> Q. Mr. Tedesco, in your opening statement, Exhibit S-9, you state at the bottom of the second page of the exhibit:
>
> > "Moreover, we now know that our actual pension expense will be higher than the amount in the Settlement Proposal."
>
> In the Settlement Proposal, you have indicated that there would be a five million dollar reduction in the pension expense. What is your estimate now as to what your actual reduction in expenses would be?
>
> A. I want to make clear we are not changing our Settlement proposal....However, it is, I think, important to recognize that based on the feedback we have very recently received from our actuaries, we had actually hoped that we would be able to reduce our pension costs by about $2.7 million dollars because of a change in interest rates of about a quarter percent. The actuary is essentially saying to us, "no." So in effect, under the terms of this settlement, our costs - - our costs, not our customer's costs - - Nova Scotia Power's costs have increased $2.7 million dollars.
>
> (Transcript, Jan 13/05, pp. 3545-3546)

7.1.2 Submissions - Intervenors

[209] Mr. Selecky, on behalf of SEB, also provided evidence concerning pension expense costs. He states in his direct evidence that NSPI's projected pension expense for 2005 is overstated. According to Mr. Selecky:

> ... NSPI's pension expense is overstated based on current market conditions. Specifically, the discount rates utilized to calculate the present value of the pension liability and the asset return assumption are understated. These rates do not reflect current market conditions. The use of a more current discount rate and asset return assumption reduces NSPI's pension liability.
>
> (Exhibit N-68, p. 4)

[210] Mr. Selecky's view is that the discount rate used by NSPI should be 6.25%, rather than the 5.75% which has been projected. As support for this contention, Mr. Selecky states:

> As previously indicated, the discount rate used to calculate the pension expense is 5.75%. In response to SEB IR-298(a), NSPI indicated that the appropriate discount rate to determine the present value of pension liabilities for accounting purposes is currently 6.25%. In response to that data response, NSPI stated the following:
>
> > If NSPI were to measure the accrued benefit obligation as at August 31, 2004, the discount rate would be 6.25%. The actual discount rate that will be used to determine the December 31, 2004 accrued benefit obligation and 2005 expense will be based on the December 31, 2004 AA bond yields – this rate will not be known until early January 2005. Recent history has seen discount rates move as much as 50 points within one to two month periods. As such, a best estimate today for December 31, 2004 would see a midpoint rate of 6.25% in a range of 5.75% to 6.75%.
>
> (Exhibit N-68, p. 5)

[211] Mr. Selecky states that, in view of this, a discount rate of 6.25% should be used to calculate the pension liabilities. He added:

> ...the discount rate to calculate the actual 2005 pension expense will be based on the AA bond yields as of December 31, 2004. The actual bond yields today provide a better estimate of the 2004 year-end bond yields than the yields that were estimated in February 2004.
>
> (Exhibit N-68, p. 6)

[212] Mr. Selecky also indicated that increasing the discount rate from 5.75% to 6.25% would reduce the projected pension expense by $5.4 million.

[213] With respect to the rate of return on assets, Mr. Selecky states that ..."the asset return assumption should also be increased to reflect the current and projected higher yield on long-term bonds." He recommends that ..."the asset return assumption be

increased from 7.5% to 8.0%. This increase reflects the increase in asset return of 50 basis points since the pension fund assumptions were developed."[32]

[214] The increase in the asset return assumption will reduce the pension expense by approximately $2.4 million, according to Mr. Selecky. As a result, the impact of increasing the discount rate, and increasing the asset return rate, will be to lower the pension expense by $7.8 million.

[215] Avon supported the position of Mr. Selecky in its closing submission, stating:

> We respectfully submit that the Board should rely on Mr. Selecky's approach to the calculation of discount rate, asset return assumption and, ultimately, NSPI's pension expense. NSPI's proposed pension expense for 2005 of $26 million is overstated. NSPI's proposed pension expense should be revised to reflect the appropriate discount rate and asset return assumption. The impact of increasing the discount rate and the asset return assumption by 50 basis points, as per Mr. Selecky's analysis, reduces the pension expense, and hence NSPI's revenue requirement, by $7.8M.
>
> (Avon, Closing Submission, p. 38)

[216] Ms. Sibson and Mr. O'Neil also gave evidence concerning the pension issue. In their direct evidence, they state that the proposed discount rate of 5.75 % put forward by NSPI is reasonable:

> The discount rate used to determine the present value of liabilities in the pension plan ...has decreased from 6.50% in 2002 (6.75% per the 2002 rate case) to 5.75% in the 2005 test year. This 2005 assumption was based on the interest rate on high quality bonds in the first quarter of 2004. The discount rate applicable to NSPI's 2005 pension expense will be determined at the measurement date used for 2004 (December 31),thus the appropriate discount rate will be in reference to market interest rates on high quality AA bonds (namely corporate bonds) as at December 31, 2004. As this date has yet to arrive, the best estimate assumption based on current interest rates on high quality bonds would be in the range of 5.5% to 6.0%...Thus, the discount rate used of 5.75% for the rate case would be considered reasonable.
>
> (Exhibit N-130, p. 3)

[217] With respect to the rate of return on assets, they state that:

---

[32]Exhibit N-68, pp. 6-7

> ... an asset return assumption of 7.5% is, in our opinion, likely at the high end of the current range of 6.5% - 7.5% for the 2005 rate case.
>
> (Exhibit N-130, p. 2)

In response to questions from the Board, Mr. O'Neil stated that:

> Q. Yes. So in your statement on page 9 -- or I'm sorry, line 9 on page 5: "The rate of return assumption is at the high end of the range, but reducing it would result in a higher expense and ultimately a higher rate increase." You're not necessarily -- or are you indicating that that's a reason why you agree that no adjustment is required?
>
> A. (O'Neil) No. We're in agreement with the rates because they're within an acceptable range. We're not directing that it should be higher or lower. It's within that range, and these are two important estimates in the whole calculation. But the whole calculation of pension expense has a number of other major factors that impact the total.
>
> (Transcript, Nov. 26/04, pp. 2085-2086)

[218] ECANS argues, in its final brief, that NSPI's pension expense be reduced by $5.4 million by increasing the discount rate to 6.25%.[33] MEUNSC, on the other hand, suggests using the actual rate once it becomes known. It states:

> The discount rate NSP used to determine the expense included in their $101.0 million additional revenue requirement request was 5.75%. Hearing estimates have placed this rate somewhat closer to 6.0%. Evidence indicated that the rate could move up to 50 basis points in a month.
>
> > "If NSPI were to measure the accrued benefit obligation at August 31, 2004, the discount rate would be 6.25 percent. <u>The actual discount rate that will be used to determine the December 24, 2004 accrued benefit obligation and 2005 expense will be based on December 31, 2004 Double 'A' Bond Yields</u>. This rate will not be known until early January 2005".
> > (Emphasis added).
> > (Blunden, transcript, pages 2120-2121).
>
> The "known" rate will no doubt be available to The Board prior to its final decision. We would urge that this is the rate which should be used to calculate the additional revenue approved for this case. Current estimates are that this rate could be 5.75-6.75%. If only the mid-point of this range is achieved a reduction of $5.4 million, in the revenue requirement is warranted.
>
> (MEUNSC, Final Brief, p. 9, emphasis in original)

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[33] ECANS, Final Brief, p. 18

7.1.3 Findings

[219] The Board notes that NSPI, in its closing submission, addresses the issue of pension costs and takes issue with Mr. Selecky's qualifications on this subject. NSPI states that:

> Pension expense is a technical and complex issue. NSPI uses Morneau Sobeco (actuary) and Grant Thornton (external auditors) to assist with and review the Company's accounting treatment. Both firms are also required to express an annual opinion on NSPI's actuarial assumptions.
>
> Ms. Sibson, along with Mr. O'Neil of PWC have filed evidence on behalf of the Board staff. Both Board witnesses are Chartered Accountants with significant experience. They recommend a discount rate of 5.5%-6%. NSPI has used 5.75% in its rate application – the exact midpoint. Secondly they suggest asset return assumptions should be in the range 6.5%-7.5%. NSPI has used 7.5%, the high end of the range. A lower pension return assumption would increase pension expense and hence the revenue requirement, would increase.
>
> Mr. Selecky (SEB) has also offered recommendations related to discount rates (6.25% representing the August 31 rate) and asset return assumptions (8.0%). Mr. Selecky is neither an actuary nor an accountant and he acknowledges he has no experience with Canadian accounting rules. He is completely unqualified to express the opinions he has. Both of his assumptions fall outside the ranges deemed reasonable by Ms. Sibson and Mr. O'Neil.
>
> Accordingly, NSPI submits that the pension assumptions used by the Company in this application are reasonable for determining the 2005 revenue requirement and that there is no acceptable evidence that should lead the Board to any other conclusion.
>
> (NSPI, Closing Argument, pp. 41-42)

[220] After considering the evidence, the Board is not persuaded that there should be any adjustment to the projected pension expense originally set out in the 2005 test year expenses. The Board understands and shares the concerns of the intervenors with respect to this significant increase in costs. The range of discount rates and asset return assumptions which were discussed reflected a valid desire to address costs where parties believed NSPI had reasonable flexibility to do so.

[221] However, as MEUNSC points out, the Board is now making its decision at a time when the actual discount rate is known. During the SA portion of the hearing, it was

clear that NSPI's estimate of 5.75% for the discount rate turned out to be correct. In addition, the evidence of Mr. O'Neil clearly indicates that NSPI used reasonable assumptions to calculate its pension costs and that its asset return assumption is not unreasonable. Accordingly, the Board makes no adjustment to the $26 million in pension expenses in NSPI's OM&G for 2005.

7.2 Miscellaneous Charges and Regulatory Changes

7.2.1 Submissions - NSPI

[222] NSPI is proposing substantial (in some cases 100%) increases in the costs of many of its miscellaneous charges. It is also proposing language amendments to certain of its Regulations concerning such items as connection and disconnection charges, wiring inspections and load research, and the introduction of a new charge for registered letters notifying customers of disconnection. According to NSPI, increases are necessary to reflect the actual cost of providing these services. NSPI indicates that:

> NSPI provides a variety of services to customers as part of its obligation to provide low-cost reliable electricity to Nova Scotians. Charges for these services are set out in Section Seven (Schedule of Charges) of the Regulations. They encompass many charges that have been in effect since 1996. Periodically, the Company reviews these charges in light of changes in service delivery, cost structures and technological advances.
>
> The most recent review of these charges suggests that they need to be adjusted. The proposed rates for the various services are attached in table format in Appendix N. With each proposed change are the key assumptions, calculation details and benchmarking data (where available) showing comparable charges for services provided by other utilities.
>
> The methodology for calculating these charges is based on recovering the fully allocated cost of each service. Labour costs and fringe benefit rates are based on expected costs in 2005. The overhead applied for Administration (84 percent) and Vehicles (23 percent) are consistent with those used in the Company's 2004 Annual Capital Expenditure Plan filed with the UARB. Cost mark-ups are based on those currently included in the approved regulations (example 7.3 (b) = 25 percent) or 10 percent where no rate is specified. Labour efficiencies and technological changes have been factored into the cost analysis where Company foresees them.

> The aggregate impact of these proposed changes is to increase the Company's revenue by approximately $2.4 million. This additional revenue in turn reduces the overall revenue requirement from above-the-line customers.
>
> (Exhibit N-1, p.109)

[223] NSPI's rates panel at the hearing consisted of Nancy Tower, General Manager of Customer Service; Mel Whalen, Director of Regulatory Affairs and Rates; Bob Boutilier, Industrial Market Leader; and Eric Ferguson, Manager of Regulatory Affairs. Under cross-examination by DLAS, Ms. Tower confirmed the manner in which NSPI arrived at the costs involved in determining certain miscellaneous charges:

Q. Great. Thank you. So 109 states that: "The methodology for calculating these charges is based on recovering the fully- allocated costs of each service." Do you see that?

A. (Tower) I do see that.

Q. Thank you. Now looking at the right-hand column back in Appendix "N", it appears that the first step in calculating the costs caused by a customer requiring a door knob notice is to take the hours of time a Customer Service Field Representative spends in the activity and multiplying it by the labour rate. Do I see that correctly?

A. (Tower) That's right. It would include -- it would include direct charges and also some charges like training, etc., that would be included in their yearly activity.

Q. So here with the door knob notice, you multiplied .42 hours times the labour cost of twenty-one dollars, forty-six cents ($21.46). It gives you about nine dollars and eight cents ($9.08), I believe. Yes.

A. (Tower) Yes.

Q. Yeah, okay. Now, to this you add an administrative and vehicle overhead of 84 percent and 23 percent respectively. Is that correct?

A. (Tower) That is correct.

Q. And in looking through Appendix "N", I see the figure is 84 percent for administrative and 23 percent for vehicle overhead. They appear consistently. So I conclude that these are standard overhead rates. Is that correct?

A. (Tower) They are. They would be rates that we would use and would have filed with the Board.

Q. Okay. Now, from my understanding once again, the administrative overhead includes costs such as office space, heating, supervision and similar costs. Is that correct?

A. (Tower) Administrative overhead would be a non -- yes, labour, rent, software, those sorts of charges.

Q. Okay. So these are basic overhead charges that the company incurs irrespective of this specific activity, and you allocate a portion of these total overhead costs to each activity. Is that right?

A. (Whalen) That is correct.

Q. Now, then you add, I notice, a 10-percent mark-up. Do you see that as well? There's a 10-percent mark-up that seems to appear consistently with door knob notices and registered letters. Can you explain what that mark-up is and what regulation allows you to use this 10-percent mark-up?

A. (Tower) The 10 percent would actually be a profit margin consistent with our rate-of-return methodology.

Q. Okay. Was there a specific regulation that allows you to use that 10-percent mark-up?

A. (Tower) Again, it's consistent with the cost-of- service methodology that we would use, and including a rate of return -- including a portion of a rate of return in that is consistent with a fully-allocated cost methodology.

(Transcript, Dec. 1/04, pp. 2905-2907)

[224] In the SA, NSPI agreed with Dr. Stutz's recommendation that there be a 50% cap on increases to miscellaneous charges.

[225] NSPI has also proposed amending the availability clause in the time-of-day rate for domestic customers. In Exhibit N-40, NSPI filed a copy of an evaluation report on Domestic Service Time-of-Day availability which had previously been requested by the Board. NSPI advised that:

> As explained in the report, the market for ETS units and other load shifting technologies has now reached the point where it is no longer appropriate for NSPI to be the only supplier. In addition, we believe that the rate should be open to new systems that can effectively be used to shift load. Consistent with these conclusions, NSPI is proposing revisions to the Domestic Service Time-of-Day Availability Clause to:
>
> 1) Remove the restriction that NSPI supply the Electric Thermal Storage equipment; and
>
> 2) Remove the restriction that the in-floor systems must be hydronic.
>
> NSPI hereby requests Board approval of the proposed new rate, as presented in Appendix A of the report. As the Board will note, only the Availability of the rate is proposed to be changed.
>
> (Exhibit N-40, p. 1)

7.2.2 Submissions - Intervenors

[226] DLAS, in its written submission, suggests the increases to these charges should be rejected because:

> Given the unaffordable nature of NSPI electric bills even without the increased miscellaneous charges, to disproportionately pass costs on to low income customers when these customers have not caused the Company to incur the costs is unconscionable and should be rejected.
>
> (DLAS, Memorandum of Law, p. 16)

[227] Dr. Stutz, in his direct evidence, also recommended that the Board reduce the proposed increase in charges as follows:

> Q. NEXT PLEASE DISCUSS NSPI'S PROPOSED CHANGES IN THE CHARGES THAT RECOVER SPECIFIC COSTS
>
> A. NSPI's regulations include a number of charges designed to cover the cost of services, such as connection or reconnection, wiring inspections and load research. NSPI has proposed substantial changes in these charges, increasing those for connection and inspections and reducing those for load research. The full set of charges is shown in Schedules 7.1, 7.2 and 7.3 included in Appendix M of the Company's initial evidence. As the support provided for the charges shows, NSPI has moved the charges to levels at or near cost.
>
> Q. DO YOU HAVE ANY CONCERNS ABOUT THE CHARGES?
>
> A. Yes, I do. Many of the changes in the charges are quite large. For example, the charges for connection or reconnection of service increase from $18 to $36. Increases of this magnitude are contrary to the criterion of rate stability.
>
> Q. DO YOU RECOMMEND ANY CHANGES IN NSPI'S PROPOSED CHARGES?
>
> A. Yes, I do. I recommend that changes in the charges be capped at 50 percent increase. This balances equity, which favors cost-based rates against rate stability. Further movement toward cost could, of course, be made in future proceedings.
>
> Q. DO YOU HAVE ANY ADDITIONAL COMMENTS RELATED TO THE INCREASES IN CHARGES?
>
> A. Yes, I do. Some of the increases in charges affect those whose service is disconnected for non-payment. In 2003 there were 2,131 such disconnections. Under NSPI's proposed regulations, the standard collection charge accompanying a notice of disconnection would increase from $13 to $21 or $27, depending on the method of notification. The reconnection charge would increase from $18 to $36. Thus, for disconnection and reconnection, the cost could increase by $32. For now the 50 percent cap I have proposed would hold the increase to $16. To put these amounts in perspective, I note that the minimum wage in Nova Scotia is $6.50 per hour. Raising the cost associated with disconnection for non-payment may not be a productive step. I would simply ask the Board to consider this point in light of whatever regulatory and other considerations it might find appropriate.
>
> (Exhibit N-134, pp. 40-42)

[228] Ms. Brockway, in Exhibit S-4, outlined her views regarding the appropriateness of a 50% increase in Miscellaneous Charges which was part of the proposed SA. She states:

> The proposed settlement would allow the Company to increase Miscellaneous Charges by as much as 50%. My first concern is with the effort to directly assign all costs of such operations to the individual customers facing disconnection. It is unnecessary and in many cases pointless to send payment-troubled customers "price signals". If such customers do not have the money to pay the underlying bill, they will not acquire that money and more merely because a disconnection or reconnection fee is applied. At the least, such fees should be waived in the case of low-income customers.
>
> (Exhibit S-4, p. 15)

[229] Mr. Epstein, on behalf of the NDP, suggests:

> Other testimony from poverty activists and respected community leaders like Jeanne Fay and Paul O'Hara are convincing in their assessment of the urgency with which the Board, and NSPI, must take account of the budgetary restraints many families in Nova Scotia face, and the NDP requests that the Board take full account of these experts' testimony. Furthermore, the doubling of the re-connection fees is an unnecessary and unjustified measure, that will prove most punitive to those who can least afford it. The NDP urges the board to reject this proposal.
>
> (NDP, Written Submission, p. 4)

7.2.3 Findings

[230] The Board is concerned with the significant increases proposed for those charges identified by NSPI as requiring an increase to recover costs. As pointed out by the intervenors, increases of up to 100% for these services are simply too high.

[231] The Board also questions the appropriateness of approving the proposed new charge for sending registered letters on overdue accounts and the proposed increase in the currently-approved disconnection notice charge. The Board notes that Ms. Brockway raised an interesting point in her evidence at the SA portion of the hearing

concerning the appropriateness of NSPI imposing this type of charge on customers. When questioned by Claire McNeil, Counsel for DLAS, she responded as follows:

> Q Okay. And you mentioned that -- earlier on, that while there has been this trend towards more direct assignment, it's not necessary, and I guess what you're saying is that like all the other costs in providing service to the domestic customers that these costs could be averaged out and paid for by the class as a whole as opposed to this design that the company has proposed of trying to make individual customers responsible?
>
> A. Yes, and there are arguments on both sides of it. I would say that the company's proposal struck me as an extreme version of the allocate the costs as much as possible to each individual customer who can be identified as causing the company to incur those costs.
>
> Q. I think you describe the fees a[s] punitive in some cases?
>
> A. Yes, I think so.
>
> Q. And just to clarify, what you're saying is that your analysis did not take into account the fact ---
>
> A Let me explain. For example, on the doorknob notice, I presume the doorknob notice is required so that somebody doesn't end up getting cut off without a chance to remedy the non-payment, if that's the problem, or challenge the bill if there is a problem there, and end up with, even if they don't have electric space heat, a water heater that doesn't work perhaps, a pump that doesn't work perhaps, so no water, a furnace motor that doesn't work, so no heat. It's in the company's interest to make sure that any customer, before they're turned off, has a chance to remedy whatever the problem is and get back on track and to -- I've never seen a company charge for a doorknob notice. Let me just put it that way. This was a new one on me.
>
> (Transcript, Jan. 14/05, pp. 3837-3839)

[232] While the Board is not prepared to reduce or eliminate the charges currently applicable to this form of notice, it does believe that the proposed charges for registered letters and disconnection notices are unnecessarily high. The Board approves a charge for $7 per registered letter, as recommended by Ms. Brockway in Exhibit S-4, Ex. NB4.

[233] With respect to the cost of disconnection notices and the other charges which are identified by NSPI as requiring an increase, the Board is of the opinion that a reasonable increase, under the circumstances, is equal to the average rate of increase for above-the-line rates. Accordingly, the Board directs NSPI to calculate these charges based on the average rate of increase for ATL rates, with the charge rounded to the

nearest dollar. The Board approves the inclusion of the proposed new items on the basis noted above.

[234] The Board notes that, in evidence set out earlier, NSPI confirmed that a 10% mark-up or profit margin is included in these charges. While NSPI is permitted to earn a return on rate base it is not appropriate, in the Board's view, to also impose a profit margin on miscellaneous charges. The Board's decision to approve a modest increase to these charges is reflective of its concern regarding this matter. In future applications, this practice should be appropriately addressed by NSPI.

[235] The Board approves the language amendments proposed by NSPI as well as the amendments to expand the availability provisions of the Time-of-Day Rate, referred to earlier in this section.

8.0 DEPRECIATION

8.1 Submissions - NSPI

[236] NSPI's application includes a depreciation expense in the amount of $127.2 million, which is $24.4 million higher than the 2002 Compliance Filing amount. This increase is explained by the Company as follows:

> Depreciation expense has increased by $24.4 million between 2002C and 2005 when it will total approximately $127.2 million. The two principal factors are:
>
> ○ Revised depreciation rates previously approved by the Board. The 2005 test year revenue requirement is calculated based on the second year of the four year phase-in of new depreciation rates approved by the Board in its Decision dated November 21, 2003 in Proceeding NSUARB-NSPI-P-879.
>
> ○ Capital additions approved by the Board since December 31, 2001 including the two LM6000 combustion turbines and the two wind turbines.
>
> (Exhibit N-1, pp. 46-47)

[237] NSPI included depreciation for two LM6000 combustion turbines at Tufts Cove Units 4 and 5 in its depreciation costs. The first LM6000 unit has been in service since 2003 and the second LM6000 was not yet in service at the time of the hearing. The Board has not approved the depreciation rate for either of these units. NSPI states:

> When the Gannett Fleming Depreciation Study was undertaken the LM6000 Combustion Turbine, Tuft's Cove Unit 4, was not in service and was therefore not included in the study. Consequently, the Board has not yet approved a depreciation rate for the combustion turbine.
>
> In the economic analysis provided to the Board as part of the capital approval process for the LM6000s, a twenty-year life was assumed. Accordingly, this Application incorporates a five percent depreciation rate on both the LM6000 combustion turbine presently installed at the Tuft's Cove Generating Station and the second LM6000 approved by the Board for Tuft's Cove in April 2004.
>
> (Exhibit N-1, p. 48)

[238] Intervenors challenged NSPI's depreciation expense primarily in respect of one issue: the appropriate depreciation life for two new LM6000 combustion turbines. SEB also questioned the inclusion of costs relating to the project to convert the Burnside combustion turbines, which includes depreciation as part of the expenses noted. This latter issue is addressed later in this decision.

[239] NSPI disagrees with the evidence of Mr. Selecky that these units should be depreciated over 30 rather than 20 years. It submits that extending the depreciation period to 30 years will result in increased costs to customers and states that:

> Mr. Selecky's recommendation would reduce depreciation expense by $1.3M in 2005 but it would increase the cost to ratepayers over time. NSPI has used 20 years based on the estimated life recommended by the manufacturer.
>
> (NSPI, Closing Argument, p. 43)

[240] In the SA, in an effort to reduce depreciation costs for the 2005 test year, NSPI agreed to delay the second year of the four year phase-in of the new depreciation rates. The SA states:

> 2.c. For 2005, depreciation fixed at $122.2 M (Board will permit NSPI to delay phase-in of the depreciation study by one year.)
>
> (Exhibit S-1, p. 3)

8.2 Submissions - Intervenors

[241] Mr. Selecky gave evidence on behalf of SEB regarding the appropriate economic life of the LM6000 units. At the hearing, Mr. Selecky stated:

> ... The third issue I take exception with is a depreciation expense for the LM 6000. NSPI has utilized a 20-year life to depreciate the unit. I believe the unit should be depreciated with a life of at least 30 years. NSPI has indicated that there will be overhauls for this unit at

> approximately every 50,000 hours of running. During those overhauls the unit will basically be brought back to initial condition if not even better, and how it can be brought back better is if GE provides enhancements that can increase the efficiency or the useful life of the machine. GE has supported these types of machines or these types of peakers for a number of years. In fact, one of the early ones was the LM 2500 that was put in service or was introduced by GE in 1968 and they still continue to support the unit and still continue to install the units. Hence, I believe that the 20- year average service life is unrealistically short.
>
> (Transcript, Dec. 2/04, pp. 3221-3222)

[242] SEB, in its written submission argues that:

> ... the estimated economic life is not the sole criterion for establishing the depreciation rate; and although it may provide the financial justification for installing the unit, "economic life" is not necessarily an indication of its useful or total life (Direct evidence of Jim Selecky, Exhibit N-68, at page 8 to 13)
>
> Again, this matter is somewhat discretionary; and despite the significant rate increases being requested, NSPI has chosen a short life (20 years) over which to depreciate the LM6000's. SEB believes that Mr. Selecky's 30 year proposal is more appropriate.
>
> (SEB Final Argument, p. 31)

8.3 Findings

[243] The Board has considered the evidence with respect to the depreciation period for the two LM6000 combustion turbines at Tufts Cove Units 4 and 5. The Board notes that in response to Undertaking U-38, NSPI indicates that its current fleet of combustion turbines has been in operation for more than 20 years and that the average retirement age for these assets is beyond 30 years. The Board finds Mr. Selecky's opinion on the expected life of LM6000 units to be very persuasive as his views appear to concur with NSPI's actual experience with similar units. The Board directs NSPI to calculate depreciation expenses for these two LM6000 units on the basis of a 30 year life rather than 20 years. The Board estimates that this will reduce NSPI's annual depreciation for the two LM6000 units by $1.3 million and the Board directs NSPI to include this reduction in its Compliance Filing.

[244] Year 2 of the 4-year phase-in of new depreciation rates, is scheduled to occur in 2005. The new rates were approved by the Board on November 21, 2003, following a review of NSPI's depreciation rates and a public hearing on the subject. The new rates and phase-in schedule were the subject of consensus between NSPI and stakeholders who participated in the process. As noted earlier, the Board has, in the past, made decisions establishing appropriate amortization periods and deferring and extending recovery periods for depreciation expenses. Since the Utility is assured that the costs will be recovered, the issue to be determined is timing—that period of time which best conforms to the principle of intergenerational equity while protecting the ratepayers from rate shock and the Utility from higher than acceptable expenses.

[245] As noted in the section of the decision on **s. 21** tax costs, this rationale has been used by the Board in the past, specifically with respect to the cost of retirement of the Glace Bay generating station. The Board is of the opinion, based on the concerns noted above, that delaying year 2 of the phase-in represents a reasonable step to reduce test year expenses and, consequently, rate increases. As a result, the Board directs the deferral of year 2 of the 4-year depreciation phase-in until 2006. The Board expects this will reduce NSPI's 2005 depreciation requirement by approximately $5 million and the Board directs that this adjustment be included in NSPI's Compliance Filing.

9.0 OTHER

9.1 Rate Assistance Program (RAP)

[246] While DLAS has opposed the approval of a FAM and the SA, and has detailed concerns regarding aspects of customer service provided by NSPI, its main focus at the hearing was the implementation of a proposed Rate Assistance Program ("RAP") to help low-income customers meet their electricity costs.

[247] DLAS filed evidence from several individuals, including Dr. Richard Shillington, a principal of Tristat Resources and Roger Colton, a principal of Fisher, Sheehan & Colton, with respect to this issue. Dr. Shillington, in his direct evidence (Exhibit N-126), outlined the challenging costs of shelter and electricity for low-income Canadians. Mr. Colton's evidence focused on low-income energy assistance programs and his efforts, in a number of US states, in designing rate affordability programs. Mr. Colton's position is that NSPI should "... be directed toward allowing low-income consumers to obtain quality utility service at affordable prices within a reasonable budget constraint."[34] Mr. Colton also submits that the costs of such a program, to be shared by customers, are offset, although perhaps not fully, by savings realized by the Utility resulting from the adoption of a 'universal service program'.[35]

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[34]Exhibit N-127, p. 12

[35]Exhibit N-127, p. 62

[248] Howard Epstein, on behalf of the NDP, also supports the universal service program as outlined by Mr. Colton.[36] Mr. Tedesco responded to questions from Counsel for DLAS on this subject as follows:

> Q. You've indicated that you'd be prepared to sit down with us voluntarily to discuss rate assistance. Why hasn't the company put forward to the Board proposals for the implementation of a rate assistance programme?
>
> A. (Tedesco) Again, we view it as a public policy issue not an electric rate issue.
>
> Q. And what does Nova Scotia -- what's the company's position with respect to the universal service programme recommended by Roger Co[u]lton?
>
> A. (Tedesco) Again, all of these things are matters of public policy.
>
> Q. So I take it from your response that you're not opposing the implementation of such a programme, you're simply saying that it's public policy.
>
> A. (Tedesco) No, I'm saying that if -- vetting the issue in a public forum, if, indeed, Nova Scotians think that that is sound public policy, we would certainly support it.
>
> Q. Okay. You would agree with me, though, that this is a public forum.
>
> A. (Tedesco) This is a rate case with an awful lot of important constituencies that probably should be present to address an issue such as folks who are below the poverty level. As I said earlier, electric rates are but one component, and there are fundamental skills that are often -- can be buttressed that can improve people's financial management skills that by themselves can make a huge difference. That is not a panacea, it's just an indication that the issue is broader than simply the price of electrons or the price of methane or the price of propane or oil for that matter.
>
> Q. Would you agree that there would be a benefit to the company, too, in the terms of the bottom line in instituting programmes such as rate assistance, including perhaps some of the programmes that you've described as well around budgeting in terms of reducing the bad debt?
>
> A. (Tedesco) Again, as I said earlier, no, I would not necessarily agree with that.
>
> Q. But what I hear you saying is that you would not oppose necessarily the implementation of such a programme here in Nova Scotia.
>
> A. (Tedesco) If it were supported broadly then of course we would -- and we were, as a matter of public policy, asked to institute such a programme, we would certainly undertake to do that.
>
> Q. You'd agree that public policy in the public interest though is a significant factor here in the deliberations of this Board.
>
> A. (Tedesco) I think the public interest is certainly part of setting electric rates.
>
> (Transcript, Nov. 17, pp. 280-283)

[36] NDP, Closing Submission, p. 4

[249] This issue was addressed by the Board in its 2002 rate decision. In that case, the Board stated:

> DLAS' principal recommendation to the Board is that it introduce a "rate subsidy program" under which low income residential customers would be subsidized by other customers of the utility. DLAS does not explain how such a program should be implemented.
>
> The Board has in the past rejected the principle of rate subsidies based on income disparity. For example, in its 1992 decision on a rate application by NSPI, the Board said this:
>
>> It was suggested that the Corporation be required to report on the affordability of domestic rates for seniors, people with disabilities and other individuals or families who are living on a fixed income. Changes to rate structures to provide subsidized rates to such persons would be discriminatory and thus contrary to the basic thrust of regulation, which is to ensure customers pay rates that are justified by the cost of serving them. The government might be interested in such a study from the social assistance viewpoint, but it is not within the regulatory mandate.
>
> **Section 67(1)** of the **Act** is pertinent to any discussion of rate subsidies:
>
>> 67(1) 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, and the Board may by regulation declare what shall constitute substantially similar circumstances and conditions.
>
> The Board recognizes DLAS' argument that, in the context of human rights legislation, the courts might well hold that differences in treatment based on differences in income level might be justified as being differences in circumstances and would not constitute discrimination. The Board has given renewed consideration to the issue of rate subsidization based on income in light of the arguments put forward by DLAS. However, it continues to hold the view that the implementation of such rate subsidy programs is neither contemplated by **s. 67(1)** nor appropriate in the context of the regulation of public utilities.
>
> The Board would note that the reduction in the revenue requirement ordered in this decision and the Board's direction that the components of the domestic and other rates shall increase by the same percentage will alleviate the disproportionate effect of NSPI's proposed rate increase on residential customers who consume low amounts of electricity.
>
> (Board Decision, Oct. 23/02, P-875, pp. 143-144)

[250] In this case, while DLAS has filed considerably more evidence regarding how such a plan would work, the threshold issue remains the same—not whether a RAP is

acceptable or advisable, but whether the Board, under the existing legislation, has the authority to implement a RAP.

[251] In its Memorandum of Law, DLAS argues that the Board has broad authority under the **Act** to exercise its responsibility to protect consumers and uphold the public interest. DLAS takes the position that **s. 44** of the **Act** is sufficiently broad to permit the Board to order the implementation of a RAP. DLAS further points out that the Board must act in a manner consistent with the equality guarantee set out in **s. 15** of the **Canadian Charter of Rights and Freedoms**. DLAS states:

> Accordingly, it is incumbent on the Board, when exercising its discretion under s. 44 of the *PUA* to make an order that is "just", to do so in a manner which is consistent with the value of Equality.
>
> It is now well settled in law that when determining the interpretive scope of inherently open-ended terms in an *Act* (such as "just"), especially in a context where access to an essential "service" is being considered, a tribunal or court should construe the term in a way which best promotes *Charter* values.
>
> Similarly, the Board's discretion in s. 44 of the *PUA* to make remedial orders must be informed by and consistent with *Charter* values. The open-ended discretion in that section is to be exercised in a manner which is compliant with *Charter* values.
>
> The requirement to have regard for *Charter* values when interpreting and exercising the discretion to make a "just" order is located in the Supreme Court of Canada's judgment in *Slaight Communications*. In that judgment, former Chief Justice Lamer stated:
>
> > ...it is impossible to interpret legislation conferring discretion as conferring a power to infringe the *Charter*, unless, of course, that power is expressly conferred or necessarily implied...Legislation conferring an imprecise discretion must therefore be interpreted as not allowing the *Charter* rights to be infringed. Accordingly, and adjudicator exercising delegated powers does not have the power to make an order that would result in an infringement of the *Charter*, and he exceeds his jurisdiction if he does so.
>
> When applied to the present application, these principles mean that the Board must be cognizant of the effect of any rate decision on people living in a low income situation. To fail to do so raises the prospect that a barrier could effectively be erected to members of a historically disadvantaged group in their ability to meaningfully access a service provided to the public. Conversely, a "just" decision by this Board is one which, not surprisingly, incorporates considerations of equality of access into this analysis.
>
> (DLAS, Memorandum of Law, pp.28-29)

[252] In the alternative, DLAS recommends that, should the Board find that it lacks the statutory authority to approve a RAP, it should recommend to the Government that the **Act** be amended to provide the Board with this authority.

[253] Board Counsel filed a written submission on the issue of the Board's jurisdiction to approve a RAP and points out that, since no Nova Scotia or Canadian case law is available on this specific question, general statutory interpretation rules must be applied in reviewing the **Act**. Board Counsel also notes that in Mr. Colton's evidence there is no "guarantee" that the costs of a RAP would be wholly offset by savings realized from the program. Accordingly, this raises the question as to whether other customers would subsidize the RAP benefit received by a defined group of low-income customers.

[254] Board Counsel points to **s. 67(1)** of the **Act** which states that:

> **67(1)** 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, and the Board may by regulation declare what shall constitute substantially similar circumstances and conditions

.

[255] As all customers, regardless of income, receive 'substantially similar' electric service from NSPI, Board Counsel concludes that:

> An interpretation of the PUA which would lead to a form of preferential treatment for low income households is not consistent with the legislative language, or with the objects and purposes set out by MacKeigan, C.J.N.S. that "rates for the various customers or classes of customers of a utility must not as between each other be unjustly discriminating or preferential".
>
> (Board Counsel, Written Submissions, p. 13)

[256] After reviewing the submissions of DLAS, Board Counsel and the relevant provisions of the **Act**, the Board finds that it does not have the statutory authority to approve a RAP. The Board has the authority given to it by the Legislature to perform its

duties in accordance with the provisions of the **Act**. The Board's role is to make decisions, based on fact and law, within the parameters of the statutory authority it has been given by the Legislature. The Board's duty is to follow public policy decisions made by the Legislature and expressed in statutes. The Board does not have jurisdiction to establish public policy. That is the role of elected officials who are accountable to the public for this function. It seems almost certain that the RAP, as described by Mr. Colton, would result in the electricity bills of certain customers, depending on their income, being subsidized by other customers. In the Board's view, this is a social and public policy question which falls within the purview of the Legislature rather than the Board. Should NSPI and DLAS wish to pursue this matter with Government, the Board would be pleased to offer assistance with respect to regulatory and ratemaking principles.

9.2 Costs - Preliminary Hearing

[257] SEB, Avon and DLAS have requested that the Board order NSPI to compensate them for costs incurred in preparation for a preliminary hearing requested by NSPI to deal with a disclosure issue immediately prior to the rate hearing. NSPI had issued IRs to certain expert witnesses, including those appearing for Board Counsel. Witnesses refused to respond to a number of these questions.

[258] On November 3, 2004, NSPI filed an application for a preliminary hearing to compel these witnesses to address these specific IRs. The Board subsequently advised that, in view of the schedule and the imminent commencement of the rate hearing, it would hear the application at the opening of the hearing. The Board, by letter dated November

5, 2004, declined a further request by NSPI to reconsider its decision to hear the preliminary matter prior to the rate case commencing, stating that:

> The Board understands and appreciates NSPI's desire to have this matter dealt with prior to the commencement of the rate case. However the Board views the disclosure issue, which NSPI has now raised, as an important matter which has the potential to significantly impact the manner in which regulatory proceedings before this Board are conducted. As such, the Board believes it is appropriate for the Board's Regulatory Panel, rather than a single Member, to deal with this issue. In terms of your concern with respect to the need for an early ruling on this question, the Board notes that even if this matter was heard next week, and the Board ruled in favour of NSPI, the type of information which is being sought by NSPI (and, potentially, by other parties in this proceeding) would not be available by the commencement of the hearing.
>
> In view of the importance of this issue, the Board also believes it is necessary to allow a reasonable period of time for intervenors, as well as NSPI, to prepare written submissions for the Board's review. As indicated in the Board's November 4, 2004 letter, the Board's schedule, and the very short period of time before the rate hearing commences, makes November 15, 2004, the most appropriate time for the Board to hear this matter.
>
> (Nov. 5, 2004 - Board Letter to NSPI)

NSPI subsequently withdrew its application for a preliminary hearing on November 10, 2004.

[259] While Avon, DLAS and SEB have all referred to this matter in their closing submission, NSPI has not responded to these claims, other than as follows:

> NSPI strongly objects to Avon characterizing as “frivolous” or “vexatious” its efforts to ensure that the hearing process is fair. The Company looks forward at the appropriate time to vigorously responding to Avon.
>
> We note that Dalhousie Legal Aid has also included a claim for costs both with respect to the withdrawn Application for a Preliminary Hearing, as well as a more general request for intervenor costs.
>
> In keeping with the Board’s practice in other cases NSPI assumes the Board will deal with all Applications for Costs after it has rendered its decision on the Rate Case. For that reason the Company reserves any discussion regarding costs until the Board has formally indicated its is prepared to hear all interested parties on that matter.
>
> (NSPI, Reply to Closing Arguments, p. 35)

[260] The Board directs NSPI to file, by May 20, 2005, its response to the application for costs which has been filed by the parties. Avon, SEB and DLAS will have

the opportunity to file additional written comments on this matter, if they wish, by May 31, 2005. The Board will then review the submissions and rule on costs at a later date.

9.3 Non-Profit Intervenor Costs

[261] Both EAC and DLAS have requested that the Board order costs be paid to compensate the organizations for their efforts in the hearing. DLAS notes that:

> The power to make an order for costs is contained in sections 12 and 28 of the *Utility and Review Board Act*. Section 6(2) of the Board's Rules of Practice and Procedure Respecting Costs states that:
>
> > 6(2) The Board may consider awarding costs against a utility to non-profit, public interest interveners with limited financial resources who:
> >
> > a) have a substantial interest in the proceeding
> >
> > b) will be affected by the proceeding
> >
> > c) participate in the hearing in a responsible way; and
> >
> > d) contribute to a better understanding of the issues by the Board
>
> This authority has been rarely used in the context of rate increase applications, in part due to the absence of non-profit interveners in Nova Scotia. The involvement of DLAS on behalf of a coalition of groups supporting the interests of low income residential customers thus can be seen as a new development, offering the Board the opportunity to address some of the systemic barriers to involvement in these matters by non profit and low income customer groups...
>
> Dalhousie Legal Aid Service receives funding from the Nova Scotia Legal Aid Commission which allows it to provide legal services and representation to clients who quality financially. Such funding does not include public interest litigation or the costs of intervention in this rate application...
>
> It is submitted that DLAS acted responsibly and prudently in these hearings. The intervention on behalf of low income consumers combined the interests of several groups and it consciously avoided duplicating the evidence already presented or made available by other interveners in the matter. It sought to identify issues and present evidence which would otherwise not be made available to the Board. Such evidence is admissible and directly relevant to the issues to be determined. As such, it is submitted that DLAS has behaved in a responsible manner to incur only such costs as were necessary to complete the evidence before the Board concerning the issues in this application...
>
> Based on the foregoing submission, it is respectfully submitted that the Board should allow the application by DLAS for costs in this application. These costs would include a reasonable sum for legal costs, as well as for reasonable disbursements incurred in retaining DLAS' experts in this matter. DLAS attaches a summary of Mr. Colton's account in this matter by way of correspondence dated December 10, 2004. Should further information be required, DLAS is prepared to offer any further particulars as directed by the Board.
>
> (DLAS, Memorandum of Law, pp. 43-46)

EAC requests that:

> Pursuant to section 12 of the Utility and Review Board Act, the Costs Rules apply to these proceedings.
>
> Section 6(2) of these Rules provide as follows:
>
> 6(2) The Board may consider awarding costs against a utility to non-profit, public interest interveners with limited financial resources who
>
> a) have a substantial interest in the proceeding;
>
> b) will be affected by the proceeding
>
> c) participate in the hearing in a responsible way; and
>
> d) contribute to a better understanding of the issues by the Board
>
> The Ecology Action Centre suggests that this submission meets the criteria of Rule 6(2) and requests an opportunity to make submissions with respect to the issue of costs in this application.
>
> (EAC, Written Submissions, final page)

[262] NSPI has not addressed the request for costs by either of these parties in its submissions. The Board directs that NSPI file its response to these requests with the Board by May 20, 2005. DLAS and EAC will have an opportunity to file additional written submissions on this issue by May 31, 2005. As with the costs applications relating to the preliminary hearing, the Board will then review the submissions and rule on the matter at a later time.

9.4 Demand Side Management (DSM)

[263] This issue was addressed by EAC and several other intervenors during the course of the hearing. In its written submission, EAC categorizes NSPI's action on DSM to be "... negligible"[37], and makes the following recommendations:

---

[37] EAC, Written Submission, p. 3

1. That the UARB request from NSPI a revised demand side management (DSM) strategy that encompasses measurable targets and timelines. The strategy should address GHG reduction initiatives, the renewable energy generation program, in-house DSM initiatives, and DSM services for customers in all rate classes.
2. That the UARB request that NSPI conduct a study investigating alternative rate designs, and engage stakeholders in the process of evaluating and selecting a rate design which most appropriately furthers economic and environmental sustainability.
3. That the UARB support in its ruling the Provincial use of systems benefit charge to facilitate funding of DSM initiatives.
4. That the UARB announce in the rate case ruling that it will conduct a demand side management hearing in 2005 to provide legitimacy to Provincial and NSPI commitments to GHG reductions and DSM.

(EAC, Written Submission, pp. 2-3)

[264] EAC also points out that DSM has been identified by the Electricity Marketplace Governance Committee ("EMGC") as a factor to be considered when determining future energy requirements. EAC also believes that NSPI, despite a 1993 DSM hearing before the Board, has not promoted DSM adequately.

[265] While Mr. Tedesco spoke of NSPI's progress on DSM issues, ECANS suggests NSPI's DSM efforts relate principally to the interruptible rider of the Large Industrial customer class. ECANS recommends that the Board direct NSPI to implement a DSM program. MEUNSC also points to the benefits of DSM efforts and the NDP suggests a continuation of the DSM hearing of the early 1990's. The Province, in its written submission, states that:

> Unfortunately, NSPI's efforts on energy efficiency and conservation measures appear to be generally limited to providing information through "bill stuffers", website information and participating in conferences designed to raise awareness with the expectation that its customers will then undertake measures that are in their own economic self-interest. This is not good enough.
>
> Since energy efficiency and conservation measures can result in savings to both NSPI and its customers, the Province submits that the utility has the obligation to assess such DSM measures in a lot more detail and to promote them with more vigour. Otherwise, the utility may be missing an opportunity to save money for both itself, and its customers. As well,

> NSPI needs to be able to benchmark the cost of DSM against the cost of adding a new capacity to address future supply/demand imbalances.
>
> (Province, Closing Submissions, pp. 34-35)

[266] NSPI had the following proposal regarding DSM:

> NSPI recognizes that spending on DSM must be shown to have clear and demonstrable benefits to customers. The Company's recent customer energy forum also underlines the strong interest that Nova Scotians have in energy conservation.
>
> The Company agrees with the concept that given the conflicting views and interests of various stakeholders, a technical conference process focused on DSM initiatives would be the most productive method of building consensus around long-term DSM targets that benefit all customers.
>
> (NSPI, Reply to Closing Arguments, p. 33)

[267] The Board has considered the helpful information provided on the matter of DSM during this proceeding. In the Board's view, further work and progress with respect to DSM is both important and necessary. The Board understands the suggestion that a DSM hearing should be held and, indeed, such a hearing may well be ordered in future. At present, however, the Board believes it is more appropriate to direct NSPI to initiate a technical conference process, with interested parties and stakeholders, to pursue an improved and effective DSM program for the Utility.

9.5 Municipal/Industrial Linkage

[268] There are six municipal utilities in Nova Scotia serving the communities of Antigonish, Berwick, Canso, Lunenburg, Mahone Bay and Riverport. These utilities are supplied with electricity by NSPI. In 2002, NSPI's rate application included a request to end the long-standing linkage in rates between municipal utilities and industrial customers. The Board indicated in its 2002 decision that it was unprepared to make such a change at

that time. As a result, NSPI's current application has continued this linkage. Other parties, however, have raised the issue of de-linkage. Both Dr. Stutz and Dr. Alan Rosenberg, a principal with Brubaker & Associates Inc., and one of SEB's expert witnesses, have advised that this linkage may no longer be justifiable. NSPI also confirmed that it has no objection to the separation of these two rates.[38]

[269] The original purpose of the linkage is set out in NSPI's response to CME IR 23 (Exhibit N-24) and was further explained at the hearing by Mel Whalen, NSPI's Director of Regulatory Affairs and Rates, when questioned by the Board:

A. (Whalen) My understanding, Commissioner Morash, is that there was a desire to set the municipal rate such that an industrial customer coming to Nova Scotia might choose to go to one of the municipal utilities or to NSPI and that the rates would not be prejudicing that decision one way or the other. It was an attempt to make the rate such that a customer would be equally comfortable going to a municipal utility -- an industrial customer would be equally comfortable going to a municipal utility.

Q. But the rate that NSPI charged the municipal was based on what? Was that based on the rate that NSPI would charge the large industrials?

A. (Whalen) Yes, I believe that was the case. The large industrial rate was calculated and then the municipal rate was set to be the same.

Q. Do you have any views as to the -- and that linkage has been maintained up to the present time, has it not?

A. (Whalen) Yes, it has.

Q. So, what are your views then, Mr. Whalen, in terms of the pros and cons of that linkage today?

A. (Whalen) I think my views would be similar to what we stated in 2002. I think there are a number of reasons now why it might be appropriate to break that linkage. Two reasons come to mind. One is that the way the municipalities set their rates -- of course, they're free to set those any way they want, and their rates have not always corresponded to ours on a class-by-class basis.

Q. And that's as we saw that evidence in the Exhibit N-200 from yesterday, is that correct, that there was an example there where they didn't necessarily correspond?

A. (Whalen) That's true, where they didn't, and I believe in 2002 we talked about that as well. A second reason is that we have not seen large industrial customers go to the municipalities even in spite of the policy. You may recall the only large industrial customer who was part of the municipality became -- applied to the Board to become an NSPI customer to be able to take advantage of the interruptible rate. And I think

[38] NSPI, Closing Argument, pp. 49-50

the third reason is that because of the energy policy that contemplates allowing the municipalities to be able to choose suppliers other than NSPI, perhaps there's no longer the same requirement to keep that linkage.

(Transcript, Dec. 2/04, pp. 3157-3159)

[270] Avon, in its closing submission, states that:

The rationale for linking the two rates as explained in Exhibit N-24 CME IR 23 has largely disappeared. The linking of the two rates has pushed the large industrial rate to 19.6% increase according to NSPI's application, an increase which would constitute rate shock in accordance with Dr. Stutz' definition.

Dr. Rosenberg also proposes to unlink the municipal rate from the large industrial rate in order to avoid shackling the large industrial rate class with the largest increase. In his direct evidence Exhibit N-67, he provides six cogent reasons for eliminating the linkage between the two rates.

We would note that the rates charged by the municipal utilities for comparable rate classes are significantly below those charged by NSPI to its rate classes. This is true either under NSPI's present rates or under the rates as proposed. There is, in our submission, no justification for further subsidization of the municipal utilities by maintenance of this unwarranted linkage.

(Avon, Closing Submsission, pp. 45-46)

[271] SEB supports ending the linkage between the two rates and recommends that Dr. Rosenberg's suggested "method 2" be used to implement this change.[39] CME also supports the separation of these two rates.

[272] MEUNSC, not surprisingly, objects to this change. It submits:

While we would agree that the opening up of the market, to the Municipal utilities in 2005, will no doubt introduce a new wrinkle to the linkage relationship it is unlikely that this issue will have any impact in the test year for this proceeding (NSP has not forecasted any changes in its revenues and / or expenses for this item). Any un-coupling based on this issue would surely only be applicable in future proceedings.

Dr. Stutz indicates, that the only reason to allow the rate components to diverge, even with the same increase, is to satisfy his requirement regarding rate shock. This is only created by the application of the Interruptible Credit to the Large Industrial customers and is, in our opinion, limited at best.

We would urge The Board to consider all of the issues associated with this item and not let the single, limited concern over-ride all of the other aspects associated with this 30 year marriage.

[39]SEB, Closing Submission, pp. 43-44

If, after all consideration, there is still a desire to separate than we would request that The Board take into account the following, when considering the rate design implications of the divorce.

1. NSP's rates are organized based on end use (Residential, Commercial, Industrial) and grouped within the end use based on size (Small, Medium, Large for Commercial and Industrial). This is a proxy for cost-based voltage level service separation (Distribution Secondary, Distribution Primary, and Transmission).

   Two of the Municipal Utilities are below 2 MVA and as such would qualify for a Medium styled application with no demand ratchet. (This load difference is presently recognized in the Cost of Service).

2. NSP only ratchets demands above 2MVA. This is based on the impact loads of this size and greater have on generation capital provisions. Given the above only four of the Municipals would warrant this concern.

3. If, as NSP states, the entire Municipal load, at only 1.6% of NSP's total requirement is of little concern (less impact then one year's growth), then we would urge The Board to consider removing the demand ratchet provision for any un-coupled rate design.

(MEUNSC, Final Brief, pp. 12-13)

[273] The Board is of the opinion that this is an appropriate time to de-link the Municipal and Industrial rate. There does not appear to be a reasonable or logical basis on which to continue the arrangement. The Board prefers Dr. Stutz's recommended proposal for distribution of revenue requirements and corresponding rate increases as a result of the separation of these two rates, and notes that NSPI concurs with this approach.[40] NSPI is directed to incorporate this change in its Compliance Filing. The Board further orders that the rate increase for municipal utilities will not take effect until May 1, 2005. The Board directs NSPI to confirm the estimated 6.1% rate increase to the six municipal utilities as soon as possible in order to provide an opportunity for these utilities to apply to the Board for a "pass-through" of this increase to their customers and mitigate the potential for lost revenue.

[40]Exhibit N-231, p. 11 and
NSPI, Closing Argument, p. 50

9.6 Annually Adjusted Rates/Below-the-Line

[274] It is clear from the evidence of SEB that the Extra Large Industrial Interruptible Rate ("ELIIR"), which was approved by the Board on January 28, 2003 as a new rate for very large customers, and the 2-part RTP rate are not offering the viable alternative option which was originally anticipated. ELIIR constitutes one of the Annually Adjusted Rates ("AARs") or below-the-line ("BTL") rates. These rates, which are not usually part of the general rate case, are set annually. They are based principally on projected fuel costs for the upcoming year which are usually put forward by NSPI in November of each year. In this case, while NSPI's estimated fuel costs in the May 28, 2004 rate case filing is $377.1 million, the fuel costs proposed to apply to AARs is significantly higher, at $393.7 million. In addition, the revenue requested to be derived from BTL rates increases from $126.3 million to $128.1 million, with NSPI's revised application on June 23, 2004.

[275] In the SA, NSPI agreed to increase the ELIIR and 2-part RTP rates by 10.4% for 2005. SEB also agreed to these increases and they are the only customers on these rates.

[276] Dr. Stutz, in his evidence regarding the SA, made the following statement:

> **Q. DO YOU HAVE ANY COMMENTS CONCERNING THE BELOW-THE-LINE RATES?**
>
> A. Yes, I do. For some time, there have been difficulties with the below-the-line rates, particularly ELIIR and the 2-part RTP. Discussions between NSPI and Stora/Bowater have led to implementation of "acceptable" below-the-line rates for winter 2005. This is an important development. Absent it the customers eligible for ELIIR might have chosen to take interruptible service on the Large Industrial rate (LIR). Because there

are no economic interruptions on the LIR, this would diminish the ELIIR customers' use of load management, likely causing others on the LIR to face more frequent interruptions during the coming winter season. However, the underlying difficulties remain.

Acceptance of the Settlement could provide a good starting point for an effort by NSPI, Staff and other interested parties to develop a long-term approach to below-the-line rates. If the Settlement is accepted the Board could require the Company to conduct discussions with Stora/Bowater, Staff and other interested parties, to determine whether, by rate design or other means, a more workable set of below-the-line rates might be developed. To ensure that any recommendations can be acted upon before the 2006 below-the-line rates need to be put in place, the parties to such a discussion could be required to report to the Board, through a consensus statement with appended individual comments, by August 1, 2005.

As was the case with fuel, the actions discussed above could be ordered whether or not the Settlement is accepted. However, as with fuel, the likelihood of productive effort may be greater if the Settlement—supported by both NSPI and Stora Bowater—is accepted.

(Exhibit S-3, pp. 6-7)

[277] This issue was addressed by NSPI, SEB (and others) in the closing submissions on the rate case portion of the hearing. SEB in its final argument, submits that:

Accordingly, SEB believes it is imperative, as set out in Dr. Rosenberg's Direct Evidence at page 41, that the ELIIR customers be entitled to continue on the current 2004 ELIIR rate until the Board renders its final decision in this rate case, with a new (2005) ELIIR rate only coming into effect concurrently with the new above-the-line rates becoming effective, and without being retroactive to January 1. Furthermore, customers should be entitled at the time both rates (LIR(IR) and ELIIR) are known to choose which rate they will use going forward. The Board will be aware that due to the significant "buy through" costs imposed in January and February, the ELIIR rate is most costly in those months, and ELIIR customers would remain subject to the "buy-through" in those months even if they chose to subsequently move to LIR(IR) once the rates are finally determined, if the Board's decision is not finalized prior to that time.

(SEB, Final Argument, p. 49)

[278] NSPI, in its reply to closing arguments, states:

In its Final Argument dated December 13, 2004, SEB argues the 2005 ELIIR should incorporate whatever fuel cost the Board approves in its decision in this case.

NSPI disagrees.

There is no reason why the fuel cost used to set ELIIR should be the same as the fuel cost in above-the-line rates. In most years this is not the case. In 2003 and 2004 for example, the fuel cost used to set annually adjusted rates was lower than the fuel cost being paid by all

> other customers. In those years, there were no objections from SEB on this issue. Annually adjustable rates can move down or up, based on the most current information used to set them. SEB are sophisticated customers and have to be taken as fully understanding all of the terms of the rates under which they agreed to take service.
>
> The effect of this would be to increase above the line rates in this rate case.
>
> (NSPI, Reply to Closing Arguments, p. 30)

[279] As noted earlier, the Board has found that the SA cannot be accepted. However, as Avon noted in its closing submission on the SA:

> Stora Enso has raised the concern that an uneconomic ELIIR rate could result in migration to the large industrial interruptible rate, leading to even more frequent interruptions. This risk of course, is of concern to our clients. However, if the Board rejects the settlement and proceeds to decision, the end result may well be rates which satisfy the below-the-line customers and the above-the-line customers and the risk of migration would dissolve.
>
> (Avon, Closing Submission, SA, p. 8)

[280] The Board is in a difficult position with respect to BTL rates in this case. Generally, these rates are set following a conventional process. Customers have the opportunity to appear before the Board to object to annual adjustments proposed by NSPI and NSPI has the same opportunity to make its case as to why an adjustment is justified. This process usually involves BTL customers only. BTL rates are expected to be based on the cost of service principles to these customers so that ATL customers do not subsidize BTL rates. The Board issues a separate decision fixing the BTL rates.

[281] Under the present circumstances, while a number of BTL customers objected to NSPI's proposed rates, a separate hearing on the BTL rates did not occur. However, the SA brought the BTL issue within this proceeding in that SEB and NSPI agreed to a 10.4% increase in the ELIIR and 2-part RTP rates. Generation Replacement Load Following ("GRLF") customers, who are also BTL customers, were not included in the SA.

[282] Reliance on the usual method for setting the BTL rates could delay a decision substantially, and introduce uncertainty in the revenues the BTL rates might produce. In the context of this decision, this would be an undesirable and inappropriate result. The Board believes that equity, fairness and the unique circumstances of this case justify a departure from the conventional process for setting these rates. The Board needs to ensure in this decision that the Utility is aware of the revenue it will receive in 2005 from all rates and that this revenue is derived from a fair and reasonable division of responsibility between ATL and BTL customers.

[283] As a result, the Board finds that it is appropriate at this time to approve a 10.4% rate increase for all BTL customers, including GRLF customers, effective January 1, 2005. The increases in the BTL rates set by the Board are equitable. The principal parties affected by this ruling are SEB and NSPI. Of the $116 million in revenue associated with BTL rates, the vast majority is paid by SEB. Had the SA, which NSPI and SEB both supported, been accepted, the BTL rates paid by SEB would have been the same as those now approved by the Board. The Board is of the view that the inclusion of GRLF customers in this group provides all BTL customers with the same treatment SEB and NSPI negotiated.

[284] Accordingly, in its Compliance Filing, the Board directs NSPI to calculate the BTL rates on the basis of a 10.4% increase.

9.7 Annually Adjusted/Below-the-Line Rates - Design Issues

[285] It has become apparent to the Board, after hearing a number of issues raised during this proceeding by both BTL customers and NSPI, that improvements in the rate design of BTL rates are necessary to ensure these rates actually work to the benefit of both ATL and BTL customers and NSPI. The Board notes Dr. Stutz's response to questions from the Board on this issue:

> Q. And in terms of -- it's clear, I think, from your evidence that you obviously have some concerns with respect to the current below-the-line rates, that work needs to be done no matter what the Board does with respect to the way those rates work.
>
> A. That's right. I feel as if I've been in an unending discussion of that set of rates going back so far that I can barely remember when it began, and I think we need to find some way of making those rates function in a way that those on them and those offering them are more comfortable with and doesn't lead to rancorous debate over and over again.
>
> (Transcript, Jan. 14/05, p. 3988)

[286] As noted earlier, the Board agrees with Dr. Stutz's comments that discussion of the BTL rates is needed and, for that discussion to be useful, it needs to occur quickly following this decision.

[287] Accordingly, NSPI is directed to convene a meeting of stakeholders, as well as Dr. Stutz and Board staff, to review this issue and attempt to resolve current outstanding problems. The Board further directs that a report reflecting progress on this issue be filed with the Board by August 1, 2005. Should adequate progress not be made, NSPI has the option of requesting that the Board hear and resolve this matter.

9.8 Light Emitting Diodes (LED)

[288] In its closing submissions, HRM outlined the issue of an LED rate:

> HRM has put forward a proposed rate for LED. In keeping with the general objective of reducing energy consumption, it is HRM's position that any steps which can be undertaken to encourage use of energy efficient lights should be supported. As Dr. Stutz in his testimony noted, it is difficult to modify behaviours to achieve conversion to more energy efficient lights and appliances. This represents an instance where the customer has come forward with a request for a rate that hopefully will support the conversion of additional intersections to LEDs but also pave the way for others to take advantage of this type of lamp.
>
> As was noted in exhibit N-203, these lamps reduce energy use by approximately 90%, reduce maintenance costs by virtue of their longer lifespan, and improve safety because lighting failure in one diode does not cause the entire indication to go dark. Traffic lights by their nature are in continual use and therefore energy use reductions provided by a traffic light have more immediate impact than lights used on a more sporadic basis...
>
> In addition, NSPI was asked in U-56 to comment on the rate proposed by HRM in Exhibit N-203 and that was not done. As a result, HRM asks that the Board to consider the adoption of the LED rate proposed by HRM.
>
> (HRM, Final Submission, pp. 43-44)

[289] Following the conclusion of the hearing, in a letter dated February 9, 2005, Mr. Whalen requested approval for a LED rate in NSPI approved Rates and Regulations, effective February 1, 2005, citing:

> The proposed rates will allow customers such as HRM to assess the business case for large scale replacement of existing incandescent traffic control lights with LED's. Such replacement will reduce energy consumption and produce savings for the customers.
>
> For 2005, NSPI expects that any conversion to LED's will have an insignificant effect on its revenue requirement or rates to other customers, so no other aspect of NSPI's rate application will need adjustment if these rates are approved.

NSPI also indicated that HRM supports this request.

[290] The Board has reviewed this issue and finds it to be a beneficial step, both from the perspective of energy conservation and customer savings. In view of HRM's agreement, and since there is no negative financial impact on customers as a result of this change, the Board approves the revised methodology in the calculation of this rate. In

addition, since rates are not affected by this change, retroactive ratemaking is not an issue and the Board has no objection to the proposed February 1, 2005 effective date. Accordingly, NSPI is directed to incorporate the revisions to its existing rate, effective February 1, 2005.

9.9 Load Forecasting

[291] Dr. Stutz raised concerns regarding NSPI's methodology to accurately predict future electricity loads. He states that:

> A. Each year NSPI develops a forecast of energy sales and peak demand. Sales are forecast for three sectors: residential, commercial and industrial. Sales to customers of the municipal utilities are included in these sectors. This year sectoral sales forecasts were developed using econometric models for residential, commercial and small and medium industrial sales. The large industrial forecast was not model based. Instead, it relied on information from customer surveys. Forecast sales by sector were allocated among the 14 rate classes for revenue forecasting purposes, and to develop peak demand.
>
> With the exception of the large customers, monthly and annual peaks were forecast based on forecast monthly energy and historical coincident load factors for each of the rate classes. For large customers, individual demand contributions to system peak were assessed based on recent history or new customer-specific information. These peak loads were adjusted for losses by rate class and are then summed to produce NSPI's forecast of Net System Peak. Non-firm Peak demand is forecast by customer. The forecast firm peak is just the residual (i.e., Net System Peak less Non-firm Peak).
>
> **Q. DO YOU HAVE ANY CONCERNS ABOUT NSPI'S FORECASTING PROCEDURES?**
>
> A. Yes, I have two concerns:
>
> - NSPI's treatment of uncertainty is very limited
> - NSPI's models are very limited in their ability to address the impacts of changes in the efficiency of energy use by customers.
>
> (Exhibit N-134, pp. 15-16)

[292] In his direct evidence, Dr. Stutz also refers to the possibility that, as a result of NSPI's load forecasting procedures, NSPI may have underestimated residential sales, at current rates, by up to $10.1 Million in 2005.[41]

[293] Dr. Stutz made the following suggestions for improvement:

> I recommend three changes in NSPI's procedures:
>
> - NSPI should produce High and Low Cases along with its Base Case using its econometrically-based forecasting equations, and include them in annual forecasting reports which should be filed with the Board.
> - NSPI should weather normalize its historic sales and demand data, use that data to forecast weather normalized future sales and demand, and then reconcile its forecast results to actual future weather normalized results as they become available. Such weather normalization efforts should be included in the annual forecasting reports.
> - NSPI should develop end-use models for the residential and commercial sectors. NSPI should use its EU models to perform the analyses discussed above. The EU models should be fully addressed in the annual forecasting reports.
>
> (Exhibit N-134, pp. 21-22)

[294] In his surrebuttal evidence, Dr. Stutz states:

> A. In my Initial Evidence I made the following recommendation.
>
> - NSPI should be directed to improve its forecasting procedures and to extend its capabilities for end-use analysis as recommended in Section 5 of my evidence.
>
> My hope in making that recommendation was that, after this proceeding, UARB Staff and Consultants could work with the Company to improve NSPI's forecasting efforts. Parts of NSPI's rebuttal suggests that a cooperative effort may prove useful.
>
> (Exhibit N-231, p. 10)

[295] NSPI referred to Dr. Stutz's evidence on this issue at the hearing in its closing submission, stating that:

> In discussing this further with Commissioner Morash, Dr. Stutz confirmed that issues related to load forecasting are perhaps best addressed subsequent to this hearing.

---

[41] Exhibit N-134, p. 25

> Q. Thank you. Now, you do spend a significant amount of your report talking about forecasting.
>
> A. I do.
>
> Q. And I believe you suggested this morning that you're not suggesting that any adjustments be made in this rate case. Is this something that you feel can be dealt with satisfactorily in the future, in the immediate future subsequent to the rate case? Is there – I guess where I'm going is there any underlying significant differences in your views as to where the forecasting should go and NSPI's approach to the forecast, or is it something you feel can be dealt with?
>
> A. The honest answer is I don't know. What I know is that the company is quite willing to discuss all of the types of forecasting issues that I've raised, and, in fact, I have had one rather extensive discussion with them. It didn't resolve all these issues. I think there may be some misunderstandings between myself and the company about what the real issues are and how serious they are and how they should be looked at, and I think what's clear to me is that in the immediate future I, and other members of the Board staff, could sit down with the company and explore all of the issues that I've raised and we may be able to resolve some of them. Some of them we may be able to resolve. So if we go through a process like that of consultation and attempt to resolve and we can't resolve them, it could be brought back to the Board certainly by the end of the coming year, if not before, but until I sit down with the company I don't know whether there's a fundamental disagreement.
>
> NSPI agrees that the approach proposed by Dr. Stutz is the best way to address any issues associated with the load forecast.
>
> (NSPI, Closing Argument, pp. 44-45)

[296] The Board shares Dr. Stutz's view with respect to the load forecasting issue. The Board accepts his recommendation and directs NSPI to initiate meetings with Dr. Stutz and Board staff to attempt to resolve these concerns.

[297] The Board also directs that a report on the progress of improvements to NSPI's load forecasting methodology be filed by December 1, 2005.

9.10 Incentive Compensation

[298] In the 2002 rate decision, the Board made the following finding with respect to incentive compensation:

The Board has heard no evidence which persuades it that ratepayers should bear 100% of the cost of incentive compensation. As Mr. Huskilson stated when questioned by Counsel for the Province as to how customers benefit from incentive compensation paid to NSPI employees:

A. Well, I think, first of all, it's important to look at the efforts of employees as not just being for shareholders, but as being for all of the stakeholders of the company. And it's very, very hard to distinguish between stakeholders of an organization, so you can't say that the success of the organization only goes to shareholders because a lot of the success of the organization goes to customers as well. As an example, in keeping rates the same between 1996 and today, that success of the organization which, in part, was driven by incentives to employees to work hard at that activity certainly was to the benefit of customers. And so from a conceptual perspective, we have a hard time understanding how you separate the benefit that the different stakeholders get from the company, so starting with that. The way that the bonus programs, as they exist today, benefit all stakeholders of the organization are that it causes employees to have a stake in the success of the organization, so employees don't get, automatically, their total compensation. They only get the compensation when they work hard, they meet goals and they meet objectives which work well for all stakeholders. At the end of the day, if you're talking about an employee being compensated, we're going to have to compensate that employee to the level that it takes to retain that employee. And we believe that it's very important that a part of that compensation be at risk for that employee and that that employee have to meet significant goals in order to be able to get those incentives. And so it's an important part of our strategy to get employees pulling in the direction of all stakeholders, which includes customers and shareholders and the general public.

Q. So you do not agree that shareholders are the primary beneficiary of these incentives.

A. It's absolutely impossible to separate one stakeholder in the operation of a company or an organization. If the company is successful, all stakeholders in that organization benefit from that.

(Transcript, April 24/02, pp. 484-486)

The Board agrees that both shareholders and ratepayers benefit from a well-run utility. The Board further agrees that it is difficult to quantify the benefit and, for that reason, reaffirms its earlier decision that an equal division of incentive compensation is the most appropriate method of allocating this cost. Accordingly, NSPI's 2002 test year expenses are reduced by approximately $1.58 million. This amount was determined by reducing the total incentive compensation costs of $3.5 million by the amount of Mr. Mann's incentive compensation and applying a factor of 50% to the remainder.

(Board Decision, P-875, pp. 56-57)

[299] In the present case, NSPI proposes no change to the 50% allocation of incentive costs to ratepayers. While no expert evidence has been filed on this issue, intervenors have raised concerns regarding the methodology used by NSPI to assess incentive compensation for employees. They ask whether ratepayers benefit as much as shareholders from the criteria used to determine incentive compensation and whether the incentives are reasonable.

[300] Avon states that:

> NSPI was requested in Av IR-4 and Av IR-5 to explain its employee incentive plans. Further information was provided in response to Undertaking U-2 and Undertaking U-20. We would submit that from a review of these materials, it is impossible to conclude that 50% of the NSPI executive goals relate to promoting the interests of ratepayers. To this extent, such bonus incentives should not be recoverable at all from the ratepayers.
>
> The more important issue, however is whether the bonus schemes in place at NSPI and the objectives sought to be achieved are aligned with the ratepayer's interests. Compensation and executive bonuses are powerful tools for motivating behavior on the part of employees. There is a reasonable basis to question the manner in which employees are being motivated when issues of obvious interest to the ratepayers are not addressed. The significant expansion in the number and dollar value of transactions with affiliated parties in circumstances where the Board's experts are unable to conclude that the transactions are for the benefit of the ratepayers is an obvious circumstance which calls for investigation of the underlying institutional motivations provided by NSPI to its employees.
>
> The fact that the Vice President of Energy Services for NSPI is eligible to receive an annual incentive equal to two percent of earnings before interest and income tax from the business operations of Emera Energy Services raises a reasonable and justifiable concern as to how he can balance conflicting interests in his dual position as VP Energy Services for NSPI and VP of Energy Services for Emera Energy. He has financial incentives for increasing the volume of transactions and therefore earnings of Emera Energy. His knowledge and experience makes him an influential member of the NSPI fuel strategy table. It is fair to question whether the progressively increasing volume of affiliate party contracts respecting fuel procurement have been influenced by the compensation scheme....
>
> We would submit that the concerns respecting the bonus and incentive plans in place for NSPI are sufficient that the Board require NSPI to prepare a comprehensive and detailed report of the bonus and incentive plans that it has in place and that the Board obtain outside expert advice to study its appropriateness to ensure that the plans not only provide value to the shareholders but also align with ratepayers' interests.
>
> (Avon, Closing Submission, pp. 51-53)

[301] HRM also addresses this issue in its submission, stating that:

> In looking at the design of the incentive program, $50,000 or 25% of the COO's annual "incentive payment" is tied to regulatory items.
>
> HRM recommends that regulatory items be considered of less importance than reliability issues, and that regulatory items become a lesser factor in scorecard success.
>
> Reliability is already a scorecard factor but is included with safety performance and environmental performance. It is suggested that reliability be made a larger factor in the incentive program and that an entire 25% be tied to improvements in the SAIFI and SAIDI indices and improvements in DSM. ...
>
> (HRM, Final Submission, pp. 26-27)

[302] MEUNSC submits that:

> As well as the concerns raised by Dr. Stutz with respect to real or apparent conflicts of interest relative to fuel issues we have NSP's failure to meet The Board's order requiring that the interests of rate payers and shareholders be non-conflicting. One needs to look no further than the issue raised regarding bonus provisions for NSP Executives being based on the success of the unregulated subsidiaries to see the problem here. An adjustment to the revenue requirement may very well be warranted to correct for the possible impacts of this continued conflict of interest.
>
> (MEUNSC, Final Brief, p. 21)

[303] The NDP states that:

> It is even more frustrating for consumers to see that while they are being asked to pay 18% + in additional rates, executives at NSPI are getting record-breaking bonuses. CEO Chris Huskilson is reported to have gotten a bonus of more than $210,600 - an amount 10 times greater than the low-income cut-off many Nova Scotians live beneath.
>
> The Board must ensure that compensation of this nature, it if is deemed to be a necessity, is an expense borne fully by the shareholders.
>
> (NDP, Written Submission, p. 5)

[304] The Board heard the opinions of intervenors with respect to the manner and amount of incentives paid by NSPI. In response to Undertaking U-2, NSPI advised that the incentives are based on the combination of the company's Economic Value Added (EVA), the company's performance and individual Scorecard performance. The total value of incentives for 2004 is $4.0 million. While the Board continues to be concerned at the level of compensation paid to senior management at NSPI, it notes that no specific evidence

has been filed which suggests that the salaries are not appropriate. Intervenors have taken issue with incentives paid and the Board continues to be of the view that ratepayers should not bear 100% of this expense.

[305] The Board has considered Avon's recommendation that NSPI should be directed to file a report on its incentive plans which could then be reviewed by outside experts in this field. In the Board's view, the purpose of such a review would be to evaluate NSPI's incentive compensation plan—its design and application—to determine whether it delivers an equal benefit to shareholders and ratepayers which would warrant the 50/50 costs-sharing currently in place. The Board finds this to be a worthwhile suggestion and, accordingly, orders NSPI to file such a report within six months of the date of this decision. The Board will engage independent experts to review this report and provide their opinion to the Board.

9.11 Burnside Combustion Turbine Units and Tufts Cove LM6000

[306] The Company currently has four combustion turbines at its Burnside location which are oil fired. In August of 2004, NSPI reactivated a request for approval of a capital expenditure to convert these units to gas fired turbines. The Board advised NSPI on November 25, 2004 that this request was not approved. The Board notes that costs related to this project are included in NSPI's 2005 OM&G expenses. Since following NSPI's application for a rate increase this project was not approved, the Board directs NSPI to eliminate any expenses related to the proposed conversion in the 2005 test year expenses in its Compliance Filing. While the project cost was $5,200,000, in its response

to Board IR 213, Exhibit N-29, NSPI estimated that eliminating expenses associated with this project from the 2005 test year would amount to approximately $554,000.

[307] In addition, as noted in the section of this decision on the SA, a new LM6000 unit, previously owned by Emera and transferred to NSPI, is now installed at Tufts Cove generating station. In its application, NSPI has included the cost of operating this additional LM6000 combustion turbine generator at Tufts Cove. It states:

> The Company's Tufts Cove generating station is comprised of three dual-fired generators, and one LM6000 natural gas-fired generator (with a second scheduled to be added by the end of 2004). ...
>
> (Exhibit N-1, p. 29)

The addition of this unit was not complete at the time of the hearing. As set out earlier, the Board approved the installation of this unit in March of 2004, on a conditional basis. The Board has received the report of PwC and Stone & Webster Canada L.P, the experts engaged by the Board to determine the appropriate transfer price for this unit. The expert's report sets the fair market value at $17,954,016, which is $841,004 less than the $18,795,020 originally proposed by NSPI. The Board, in a separate decision, approved the fair market value of the unit at $17,954,016, as recommended by the experts, and directed that NSPI's 2005 costs relating to the operation of this unit be reduced accordingly and reflected in NSPI's Compliance Filing. The Board estimates this reduction to be approximately $90,000.

10.0 SUMMARY OF DISALLOWANCES AND ADJUSTMENTS

[308] NSPI, in its June 23, 2004 filing, projected a revenue requirement for 2005 of $1,072.9 million. This represents an increase of $32.7 million over the May 28, 2004 filing which, in turn, had proposed a revenue requirement increase of $71 million.[42] Accordingly, in this application, NSPI seeks a revenue requirement increase of approximately $104 million.

[309] NSPI illustrates the increases sought from customers, including the resulting revenue cost ("R/C") ratios and total revenue requirement in the following table:

[42] Transcript, Nov. 16/04, pp. 27-28

	Current Revenue	May 28th Submission Costs	Proposed Revenues	Revenue Increase	Revenue % Increase	R/C Ratios	June 23rd Submission Costs	Proposed Revenues	Revenue Increase	Revenue % Increase	R/C Ratios
ABOVE-THE-LINE CLASSES											
Residential											
Total Residential	**$406.8**	**$458.3**	**$448.5**	**$41.7**	**10.2%**	**97.9%**	**$474.5**	**$464.2**	**$57.4**	**14.1%**	**97.8%**
Commercial											
Small General	$23.2	$25.2	$25.2	$2.0	8.6%	100.1%	$26.1	$26.1	$2.9	12.4$	100.0%
General Demand	$214.9	$210.9	$221.4	$6.6	3.1%	105.0%	$218.1	$229.0	$14.1	6.6%	105.0%
Large General	$29.5	$33.5	$32.8	$3.3	11.2%	97.9%	$34.6	$33.8	$4.3	14.8%	97.8%
Total Commercial	**$267.5**	**$269.5**	**$279.4**	**$11.9**	**4.4%**	**103.7%**	**$278.7**	**$288.8**	**$21.3**	**8.0%**	**103.6%**
Industrial											
Small Industrial	$20.1	$21.7	$21.9	$1.7	8.6%	100.6%	$22.5	$22.6	$2.5	12.4%	100.7%
Medium Industrial	$41.3	$44.9	$44.8	$3.6	8.6%	99.8%	$46.4	$46.4	$5.1	12.4%	100.0%
Large Industrial	$54.9	$62.7	$63.4	$8.5	15.5%	101.1%	$64.8	$65.6	$10.8	19.6%	101.3%
Total Industrial	**$116.3**	**$129.3**	**$130.1**	**$13.8**	**11.9%**	**100.5%**	**$133.6**	**$134.6**	**$18.4**	**15.8%**	**100.7%**
Other											
Municipal	$12.7	$14.7	$14.4	$1.8	13.9%	97.9%	$15.2	$14.9	$2.2	17.6%	97.8%
Unmetered	$20.4	$22.8	$22.3	$1.9	9.3%	97.9%	$23.6	$23.1	$2.6	12.9%	97.8%
Total Other	**$33.1**	**$37.5**	**$36.7**	**$3.7**	**11.1%**	**97.9%**	**$38.8**	**$37.9**	**$4.9**	**14.7%**	**97.8%**
Total A/L Classes	**$823.7**	**$894.7**	**$894.7**	**$71.0**	**8.6%**	**100.0%**	**$925.6**	**$925.6**	**$101.9**	**12.4%**	**100.0%**
Total B/L Classes			**$126.3**					**$128.1**			
Total All Classes			**$1,021.0**					**$1,053.7**			
Exports			**$7.3**					**$7.3**			
Miscellaneous			**$11.9**					**$11.9**			
Total Revenue Requirement			**$1,040.2**					**$1,072.9**			

(Excerpt from Exhibit S-1, Rate Changes, p. 1)

[310] As the Board has outlined in this decision, a number of disallowances and adjustments have been made which reduce NSPI's 2005 revenue requirement. These are set out below:

Disallowances and Adjustments	
ITEM	**DISALLOWANCES AND ADJUSTMENTS**
Disallowance - fuel costs	$18,000,000
Reduced ROE of 9.55%	$6,900,000
Deferral of s. 21 costs for 2005	$21,400,000
Extend depreciation period for 2 LM6000s from 30 to 20 yrs.	$1,300,000
Deferral of Depreciation phase-in	$5,000,000
Eliminate Operating Cost of Burnside CT conversion	$554,000
Cost Reduction - Tufts Cove LM6000 Unit 5	$90,000
Total disallowances and adjustments	**$53,244,000**

[311] The Board understands that the $53,244,000 disallowances and adjustments listed above are estimates based on the evidence filed during the hearing. The Board also estimates that, because of tax impacts, the $53,244,000 in disallowances and adjustments will result in a reduction of approximately $70 million in NSPI's test year revenue requirement. The Board directs NSPI, through the Compliance Filing, to confirm the actual reduction in revenue requirement which flows from this decision.

[312] As noted earlier, NSPI requested an increase in its revenue requirement of approximately $104 million. This request resulted in a proposed average increase for above-the-line customers of 12.4%, with an increase of 14.1% for domestic customers. The disallowances and adjustments directed by the Board and noted above, are expected to result in an approximate average rate increase of 5.3% for above-the-line customers. Most above-the-line customers, including domestic customers, can expect a rate increase of approximately 6.1%. The increase in rates for ATL customers (other than municipal utilities)

is effective April 1, 2005. For the reasons set out in this decision, all below-the-line customers will see an increase of 10.4% in rates, effective January 1, 2005.

[313] The Board continues to be of the view expressed in the 2002 rate case decision that it is desirable to maintain, where reasonable, an R/C ratio of 95% to 105%. The Board recognizes that the General Demand rate category did not fall within the 95% to 105% R/C range in 2002. The Board believes it is fair and reasonable, in terms of the impact on other ATL customers, for this rate group to be gradually moved to the 95% to 105% R/C ratio. It directs NSPI to base its adjustments in the Compliance Filing on the principles noted above.

11.0 SUMMARY OF BOARD FINDINGS

11.1 Rate Increase Despite Pending Power Outage Review

[314] As part of the outage review, the Board has received a number of comments from members of the public questioning, among other things, why NSPI's request for a rate increase should be considered when the service provided by NSPI is, in the view of these customers, inadequate and unsatisfactory.

[315] While the Board recognizes the logic of this reaction, it is important to understand why this form of sanction cannot reasonably be applied to a regulated utility. Providing electricity to all communities in the Province was not (and likely still is not) financially feasible for private, competitive companies. For that reason, the Province's electric service supplier is a cost-of-service monopoly. In return for undertaking and continuing the costs of electrification of the Province, the Utility is permitted, under the **Act**, to recover the reasonable and prudent costs of providing this service.

[316] Rates charged to customers are based on costs incurred by the Utility in providing service. If the Board finds certain costs to be imprudent or unreasonable, it can (and has) disallowed such expenditures and reduced proposed rate increases accordingly. The Board cannot, however, make rate decisions based solely on reliability issues or current public opinion of the Utility. There are appropriate sanctions a regulator can impose should a Utility be found to have an inadequate or unreliable system. In many cases, it is likely such sanctions would involve higher expenditures, rather than reductions in costs. However, the practical reality in a regulated utility environment is that sanctions for service-related issues do not generally include a moratorium on rate increases.

11.2 Settlement Agreement

[317] The Board concludes that acceptance of the Settlement Agreement (“SA”) is not warranted in this case. The Board wishes to make it clear that its conclusion is based on certain unacceptable terms in the SA and is not as a result of a negative view on the Board’s part regarding SAs in general. The principal reason for rejection of the SA concerns fuel. If the SA were to be accepted by the Board, the significantly higher cost of fuel projected by NSPI would be passed on to ratepayers, either in 2005 or, in later years, by deferral. The evidence heard by the Board during the rate hearing simply does not warrant this result.

11.3 Fuel Procurement Strategy and Prudency

[318] NSPI, in the Board’s view, failed to address its imported coal procurement problems quickly or efficiently enough, following the 2002 rate hearing and decision, to adequately protect itself or its ratepayers. As a result, NSPI and its ratepayers face higher than necessary costs. The Board finds that NSPI has been imprudent in its fuel procurement practice and the cost of fuel and purchased power approved by the Board for the 2005 test year is reduced by $18 million. The Board wishes to make it clear that, in its view, this is not a reflection on the integrity or intentions of individuals, particularly those who were part of NSPI’s fuel decision-making process. It does, however, reflect a corporate philosophy which did not change with the urgency and purpose required in the circumstances.

11.4 Affiliate Activity

[319] Fuel procurement decisions should not be overseen or influenced by individuals whose work relates primarily to unregulated affiliates. As a result, the Board directs that Todd Sattler, so long as he continues to be an employee of Emera Energy or Emera Energy Services, or any other unregulated affiliated company, no longer participate in NSPI's fuel strategy table. While the Board understands the similar concerns expressed regarding Mr. Huskilson's participation in the fuel strategy table, it is not prepared, in view of his positions with Emera and NSPI, to direct his removal from the fuel strategy table and decision-making process at this time.

[320] NSPI is also directed to promptly engage high level in-house expertise to lead the imported coal supply aspect of its fuel procurement process and to establish a more efficient and accountable decision-making structure with respect to fuel procurement. NSPI is directed to file a report with the Board, within six months from the date of this decision, outlining the implementation of the changes noted above. The Board will engage the services of independent fuel experts to review the adequacy of NSPI's actions to address this issue. In addition, along with the current review on NSPI's annual filing on affiliate transactions performed by an accounting firm, the Board will also retain fuel audit experts to examine and express their opinions on affiliate transactions, including export sales and natural gas sales.

11.5 Fuel Adjustment Mechanism (FAM)

[321] The Board recognizes that FAMs exist in many other jurisdictions and can, potentially, be a positive and useful regulatory tool. However, in view of the Board's findings with respect to imprudence and inadequacies in NSPI's fuel procurement practices, it would be quite inappropriate to approve a FAM at this time as the Board does not believe it is in the public interest to transfer the risk of fuel price volatility to ratepayers when NSPI's ability to achieve the best possible fuel price is in question.

[322] Should NSPI apply for approval of a FAM in future, the Board will order an independent audit by Board-appointed fuel experts of NSPI's overall progress and performance with respect to necessary fuel procurement improvements. This audit would form part of the evidence the Board would consider in a future FAM application.

11.6 Return on Equity (ROE) and Capital Structure

[323] The Board believes that an ROE of 9.55% is fair and reasonable in the circumstances. The ROE requested by NSPI is, in the opinion the Board, too high given the current economic climate. The Board approves an ROE at 9.55% for the purpose of setting rates, with the earnings range set at 9.30% to 9.80%.

[324] The Board approves the proposed increase in the common equity ratio for ratemaking purposes from 35% to 37.5%. The Board is satisfied that the strengthening of the balance sheet in this way is desirable in the current economic climate and reflective of Emera's common equity ratio.

[325] The Board directs NSPI to use a return on rate base methodology for the next rate application. It is not necessary, nor is there sufficient evidence on this point, in the Board's view, to determine in this proceeding if NSPI is correct in its suggestion the revenue requirement should not be impacted by this change.

11.7 Section 21 Tax Costs and Amortization

[326] Generally, taxes are a reasonable cost which utilities are expected to recover. The **s. 21** taxes owed by NSPI fall into this category. The Board finds that there is not sufficient evidence to establish that NSPI acted imprudently in its decision not to pay the full amount of the **s. 21** at the earliest possible time.

[327] The Board is mindful that an appropriate balance needs to be achieved in easing the impact of this increase in costs on ratepayers without extending the recovery period for such a long period of time that intergenerational equity is compromised. The Board must balance what is a reasonable and fair amortization period with the interests of ratepayers and the avoidance of rate shock. The Board finds that amortization of the **s. 21** taxes should be deferred for 2005 and 2006 and, in 2007, amortization over an 8 year period should commence. The Board is satisfied that this approach is reasonable for ratepayers and NSPI and complies with the regulatory principle of intergenerational equity.

[328] The Board also finds that a levelized revenue requirement over the 8 year amortization period is appropriate. This approach will eliminate the \$21.4 million amortization in the 2005 test year and, according to NSPI's evidence, will result in an actual reduction in NSPI's 2005 revenue requirement of approximately \$32.7 million.

11.8 Operating, Maintenance & General Expenses (OM&G)

11.8.1 Pension Costs

[329] The Board is not persuaded that there should be any adjustment to the projected pension expense originally set out in the 2005 test year expenses. The evidence clearly indicates that NSPI used reasonable assumptions to calculate its pension costs. Accordingly, NSPI's estimated 2005 pension expenses of $26 million will not be reduced.

11.8.2 Miscellaneous Charges and Regulatory Amendments

[330] The Board is concerned with the significant increases (up to 100%) proposed for miscellaneous charges and finds the requested increases to be too high. The Board is of the opinion that a reasonable increase, under the circumstances, is equal to the average rate of increase for above-the-line rates rounded to the nearest dollar. This modest increase also reflects the Board's concern with NSPI's practice of including a 10% profit margin in its calculation of these charges which the Board finds to be inappropriate. NSPI is directed to address this practice in future applications.

[331] The Board approves the inclusion of the proposed new items, including a $7 charge per registered letter. The Board approves the language amendments proposed by NSPI as well as the amendments to expand the availability provisions of the Time-of-Day Rate.

11.9 Depreciation

[332] The Board directs NSPI to calculate depreciation expenses for the two LM6000 combustion turbine units at Tufts Cove Units 4 and 5, on the basis of a 30 year life rather than 20 years. The Board estimates that this will reduce NSPI's annual depreciation for these units by $1.3 million and directs NSPI to include this reduction in its Compliance Filing.

[333] In addition, the Board directs the deferral of year 2 of the 4-year phase-in of depreciation rates until 2006. This is similar to past decisions the Board has made to establish appropriate amortization periods and to defer and extend recovery periods for depreciation expenses. The Board expects this will reduce NSPI's 2005 depreciation requirement by approximately $5 million and the Board directs that this adjustment be included in NSPI's Compliance Filing.

11.10 Rate Assistance Program (RAP)

[334] The Board finds that it does not have the statutory authority to approve a RAP. It is almost certain that the RAP would result in the electricity bills of certain customers, depending on their income, being subsidized by other customers. In the Board's view, this is a social and public policy question which belongs to accountable elected officials in the Legislature rather than the Board.

11.11 Costs - Preliminary Hearing

[335] SEB, Avon and DLAS have requested that the Board order NSPI to compensate them for costs incurred in preparation for NSPI's requested preliminary hearing on a disclosure issue. The Board directs NSPI to file its response to the application for costs which has been filed by the parties by May 20, 2005. Avon, SEB and DLAS will have the opportunity to file additional written comments on this matter if they wish, by May 31, 2005. The Board will then review the submissions and rule on the matter at a later date.

11.12 Costs - Non-Profit Intervenors

[336] Both EAC and DLAS have requested costs to compensate them for their efforts in the hearing. NSPI has not addressed the request for costs by either of these parties in its submissions. The Board directs that NSPI file its response to these requests with the Board by May 20, 2005. DLAS and EAC will have an opportunity to file additional written submissions on this issue by May 31, 2005. The Board will then review the submissions and rule on the matter at a later time.

11.13 Demand Side Management (DSM)

[337] In the Board's view, further work and progress with respect to DSM is both important and necessary. A DSM hearing may be ordered in future. At present, however, the Board believes it is more appropriate to direct NSPI to initiate a technical conference

process, with interested parties and stakeholders, to pursue an improved and effective DSM program for the Utility.

11.14 Municipal/Industrial Linkage

[338] The Board is of the opinion that this is an appropriate time to de-link the Municipal and Industrial rate as there does not appear to be a reasonable or logical basis on which to continue the arrangement.

[339] The Board prefers Dr. Stutz's recommended proposal for distribution of revenue requirements and corresponding rate increases as a result of the separation of these two rates, and notes that NSPI concurs with this approach. NSPI is directed to incorporate this change in its Compliance Filing. The Board orders that the effective date of the rate increase for municipal utilities is May 1, 2005, and NSPI is directed to confirm the estimated 6.1% rate increase to the six municipal utilities as soon as possible. This provides an opportunity for these utilities to apply to the Board for a "pass-through" of this increase to their customers and mitigate the potential for lost revenue.

11.15 Annually Adjusted/Below-the-Line Rates

[340] The Board believes that equity, fairness and the unique circumstances of this case justify a departure from the conventional process for setting these rates. The Board needs to ensure that in this decision the Utility is aware of the revenue it will receive in 2005

from all rates and that this revenue is derived from a fair and reasonable division of responsibility between above-the-line and below-the-line customers.

[341] As a result, the Board finds that it is appropriate at this time to approve a 10.4% rate increase for all BTL customers, including GRLF customers, effective January 1, 2005. The increases in the BTL rates set by the Board are equitable. The principal parties affected by this ruling are SEB and NSPI. Of the $116 million in revenue produced by the BTL rates, the vast majority is paid by SEB. Had the SA, which NSPI and SEB both supported been accepted, the BTL rates paid by SEB would have been the same as those now approved by the Board.

11.16 Annually Adjusted/Below-the-Line Rates - Design Issues

[342] The Board agrees with Dr. Stutz's comments that discussion of the BTL rates is needed and, for that discussion to be useful, it needs to occur quickly following this decision. NSPI is directed to convene a meeting of stakeholders, as well as Dr. Stutz and Board staff, to review this issue and attempt to resolve current outstanding problems. The Board further directs that a report reflecting progress on this issue be filed with the Board by August 1, 2005. Should adequate progress not be made, NSPI has the option of requesting that the Board hear and resolve this matter.

11.17 Light Emitting Diodes (LED)

[343] The Board approves the post-hearing request of NSPI, consented to by HRM, for inclusion of a LED rate. The Board has reviewed this issue and finds it to be a beneficial step, both from the perspective of energy conservation and customer savings. In view of HRM's agreement, and since there is no negative financial impact on customers as a result of this change, the Board approves the revised methodology in the calculation of this rate. NSPI is directed to incorporate the revisions to its existing rate, effective February 1, 2005.

11.18 Load Forecasting

[344] The Board is concerned about NSPI's methodology of load forecasting and directs NSPI to initiate meetings with Dr. Stutz and Board staff to attempt to resolve these concerns. The Board also directs that a report on the progress of improvements to NSPI's load forecasting methodology be filed by December 1, 2005.

11.19 Incentive Compensation

[345] While the Board continues to be concerned at the level of compensation paid to senior management at NSPI, it notes that no specific evidence has been filed which suggests that the salaries are not appropriate. Intervenors have taken issue with incentives paid and the Board continues to be of the view that ratepayers should not bear 100% of this expense.

[346] The Board directs NSPI to file a report on its incentive plans which could then be reviewed by outside experts in this field. The purpose of such a review is to evaluate NSPI's incentive compensation plan—its design and application—to determine whether it delivers an equal benefit to shareholders and ratepayers which would warrant the 50/50 costs-sharing currently in place. The Board orders NSPI to file such a report within six months of the date of this decision. The Board will engage independent experts to review this report and provide their opinion to the Board.

11.20 Burnside Combustion Turbine Units

[347] The Company currently has four combustion turbines at its Burnside location which are oil fired. In August of 2004, NSPI reactivated a request for approval of a capital expenditure to convert these units to gas fired turbines. The Board advised NSPI on November 25, 2004 that this request was not approved. The Board notes that costs related to this project are included in NSPI's 2005 OM&G expenses. The Board directs NSPI to eliminate any expenses related to the proposed conversion in the 2005 test year expenses in its Compliance Filing. It is estimated that, based on NSPI's evidence, eliminating the expenses associated with this project from the 2005 test year will amount to approximately $554,000.

11.21 Tufts Cove LM6000 Unit

[348] A new LM6000 unit, previously owned by Emera and transferred to NSPI, is now installed at Tufts Cove generating station. The addition of this unit was not complete

at the time of the hearing. The Board approved the installation of this unit in March of 2004, on a conditional basis. The Board has received the report of PwC and Stone & Webster Canada L.P, the experts engaged by the Board to determine the appropriate transfer price for this unit. The expert's report sets the fair market value at $17,954,016, which is $841,004 less than the $18,795,020 originally proposed by NSPI. The Board, in a separate decision, has approved the fair market value of the unit at $17,954,016, as recommended by the experts, and directed that NSPI's 2005 costs relating to the operation of this unit be reduced accordingly and reflected in NSPI's Compliance Filing. The Board estimates this reduction to be approximately $90,000.

11.22 Disallowances and Adjustments/Rate Increase

[349] The Board has made disallowances and adjustments totalling $53,244,000. It estimates that, because of tax impacts, this will result in an approximate $70 million actual reduction of NSPI's test year revenue requirement. This, in turn, is expected to result in an average rate increase of approximately 5.3% for above-the-line customers, with an estimated rate increase of approximately 6.1% for most of these customers, including domestic customers. The increase in rates for most above-the-line customers is effective April 1, 2005. All below-the-line customers will see an increase of 10.4% in rates, effective January 1, 2005.

An Order will issue accordingly.

DATED at Halifax, Nova Scotia, this 31st day of March, 2005.

Margaret A. M. Shears, Vice-chair

Kulvinder S. Dhillon, P. Eng., Member

John A. Morash, C.A., Member

APPENDIX - A

List of Witnesses

On behalf of	**Witness**
NSPI	Chris Huskilson
	Ralph Tedesco
	Dr. Roger Morin
	Tim Simard
	Rick Janega
	James Taylor
	Emily Medine
	Todd Sattler
	Richard J. Daw
	Gordon Lawlor
	Ron Smith
	Zeda Redden
	Robert Boutilier
	Greg Blunden
	Melvin Whalen
	Nancy Tower
	Eric Ferguson
BOARD COUNSEL	James A. Rothschild
	Elaine Sibson
	J. Patrick O'Neil
	John B. Adger
	Dennis Kalbarczyk
	John Antonuk
	Donald T. Spangenberg
	Dr. John Stutz
	Nancy Brockway
AVON VALLEY GREENHOUSES LTD.	Billie S. LaConte
	Dr. Manfred Raschke
	Mark Drazen

STORA ENSO & BOWATER MERSEY	Michael Gorman Douglas Ewens, Q.C. Sharon Hennings James Selecky Dr. Alan Rosenberg Colin V. Gubbins Richard Marston
EVENING SESSION (Nov. 24, 2004)	Rick Clarke - Nova Scotia Federation of Labour Alistair Sinclair, Betty Robertson - Face of Poverty Consultation Mike Wadsworth - Kesme Enterprises Limited Bob Cook, Marjorie Sullivan and Peter Nestman - Nova Scotia Association of Health Shawn Hingley - Highland Vegetation Management Ltd. John Miller, Brooklyn, NS Michel Samson, MLA - Liberal Caucus Office Wayne Gaudet, MLA - Liberal Caucus Office Jim Murphy - Liberal Caucus Office David McRury - Liberal Caucus Office Nick MacLean - Ecology Action Centre Linda Arbuckle, Dartmouth, NS Brooke Taylor, MLA - PC Caucus Office Murray Scott, MLA - PC Caucus Office Rev. Mark Parent, MLA - PC Caucus Office Alain Joseph - On behalf of Professor Larry Hughes, Dalhousie University Jeanne Cruikshank - Canadian Council of Grocery Distributors

APPENDIX - B

List of Formal Intervenors

Antigonish, Town of	Brian R. MacNeil
Avon Valley Greenhouses Ltd. Canadian Salt Company Limited Cerescorp Company Crown Fibre Tube Inc. Halifax Grain Elevator Limited Halterm Limited High Liner Foods Inc. Imperial Oil Limited Intertape Polymer Inc. J.D. Irving Ltd., Saw Mills Division Maritime Paper Products Ltd. Michelin North America (Canada) Inc. Minas Basin Pulp & Power Company Ltd. Oxford Frozen Foods Limited Statia Terminals Canada Incorporated Trentonworks Limited	Robert G. Grant, Q.C, Nancy G. Rubin
Barrington Wind Energy Limited	Erik Twohig and David Lawson
Breton Windworks Inc.	Robert Leth
Canadian Manufacturers & Exporters	J.D.R. (Dick) Smyth, P.Eng.
Cape Breton Regional Municipality (CBRM)	John Whalley
Dalhousie Legal Aid Service	Megan Leslie and Claire McNeil
Ecology Action Centre	Howlan Mullally and J. Jeff Bell
Electricity Consumers Alliance of Nova Scotia	John Woods, P.Eng.
Eskasoni Band Council and Eskasoni Power and Energy	Robert Leth, Gregory Johnson and Chief Blair Francis
GasWorks Energy Corp	Dwight Jeans and J. Peters
Halifax Regional Municipality	Mary Ellen Donovan and Karen Brown
Heritage Gas Limited	Marilyn P. Wappel and Chris Smith

Liberal Caucus Office (Nova Scotia)	Michel Samson, Diana Whalen
Town of Lunenburg	N.A. (Norman) Mossman and Bea Renton
Maritime Steel & Foundries Ltd.	Fred J. Dickson and Donald Cameron
Municipal Electric Utilities of Nova Scotia Co-operative	Donald Regan and Albert Dominie
New Democratic Party Caucus Office (NDP)	Howard Epstein, Paul Black
Province of Nova Scotia	Stephen T. McGrath Jeannine A. Lagassé,
Quetta Inc.	John H. Reynolds, P.Eng.
Stora Enso Port Hawkesbury Limited and Bowater Mersey Paper Company Limited	George T.H. Cooper, Q.C David MacDougall Michael Simms

APPENDIX - C

Code of Conduct and Order

Schedule “A” to Board Order dated November 9, 2004

NOVA SCOTIA POWER INC.
CODE OF CONDUCT
Effective January 1, 2005

1.0 PURPOSE

1. The primary purpose of this Code of Conduct is to ensure that transactions between Nova Scotia Power Inc. (NSPI) and its affiliates[1] demonstrate a benefit to the customers of NSPI.

2.0 STATEMENT OF PRINCIPLES

2.1 NSPI’s management will conduct the company’s transactions with affiliates in such a way that its utility customers benefit from such transactions.

2.2 NSPI’s customers will not otherwise bear the risks or share the rewards of an affiliate’s activities.

2.3 Competition in markets where NSPI’s affiliates are active will not be impaired by non-market behaviour by NSPI.

3.0 CORPORATE STRUCTURE

Objectives

To separate regulated electric and other utility services[2] from affiliate activities.

---

[1]For the purpose of this Code of Conduct, the term “affiliate” shall be interpreted in accordance with Sections 2(2), 2(3), and 2(4) of the Nova Scotia Companies Act.

[2]Regulated electric and other utility services are those covered by the Public Utilities Act.

Protocols

3.1 EMERA, the parent company of NSPI, will create and maintain a corporate organizational structure which ensures that regulated electric and other utility services are provided solely by NSPI and by no other affiliate.

3.2 NSPI will maintain a complete list of all of its affiliates. The list will include the name and address of each affiliate, a brief description of its activities and the names, addresses and telephone numbers of all of its officers. The list will be kept on open file with the Nova Scotia Utility and Review Board (Board).

4.0 UTILITY MANAGEMENT

Objectives

To dedicate to the provision of regulated services, in terms of quality and numbers, a management team capable of maintaining a superior level of performance, at the same time as NSPI affiliates are expanding into other business activities.

Protocols

4.1 NSPI will maintain a management team capable of delivering a superior level of performance.

4.2 NSPI will prepare and submit to the Board an annual report which summarizes utility performance. The report format, and contents thereof, shall be agreed upon in advance between NSPI and the Board.

5.0 UTILITY FINANCING

Objectives

To maintain a capital structure for NSPI which is in accordance with applicable Board decisions.

Protocols

5.1 NSPI's capital structure will reflect the Board approved capital structure.

5.2 NSPI's capital structure will not be used to subsidize affiliate activities. Affiliate risks or losses will not be borne by NSPI's customers.

5.3 NSPI shall not, without the prior approval of the Board, provide loans to, guarantee the indebtedness of, or invest in securities of an affiliate.

6.0 FAIR DEALING

Objectives

To avoid discrimination in the matter of pricing or in any other manner against non-affiliated buyers of regulated electric utility services.

To avoid NSPI subsidizing or being subsidized by the activities of affiliates.

Protocols

6.1 NSPI will provide access to regulated utility services on a non-discriminatory basis and will not in respect of those utility services directly or indirectly state, imply or offer any preference or favoured treatment to NSPI's affiliates or persons purchasing affiliate goods and services.

6.2 The financial records of NSPI, as well as NSPI's information systems, will be kept separate from those of its affiliates.

6.3 NSPI will not provide confidential customer information to affiliates or other persons without prior customer consent.

6.4 NSPI will provide customer information to NSPI affiliates and non-affiliates in a non-discriminatory manner.

6.5 NSPI will charge Board approved rates for all regulated electric and other utility services provided to affiliates.

6.6 NSPI will charge and be charged a market rate of return for any assistance it provides to or receives from affiliates by way of a guarantee or loan.

6.7 NSPI will charge and be charged prices which reflect fair market value for all non-regulated utility goods and services provided to affiliates or purchased from affiliates, provided that in no case shall NSPI supply such goods and services at a loss.

6.8 Where prices based on market value cannot be established, NSPI will charge prices which reflect the utility's fully-allocated costs for the goods and services provided.

6.9 Where a capital asset is transferred from NSPI to an affiliate or from an affiliate to NSPI, that asset will be transferred at a price to be approved by the Board in advance.

6.10 The costs of corporate support services[3] will be fairly allocated between NSPI and its affiliates. The allocation factor employed will depend on the nature of the corporate support services.

6.11 Before an activity is transferred from NSPI to an affiliate or from an affiliate to NSPI, NSPI must ensure there is a demonstrated benefit to its customers.

7.0 ACCOUNTING COMPLIANCE

Objectives

To separately and fully account for the value of goods, services, financial and other support delivered to or from NSPI and its affiliates.

Protocols

7.1 NSPI shall report annually to the Board the following information:

(a) A detailed listing of all assets, services and products provided to and from NSPI and each of its affiliated companies.
(b) Each item on the listing should indicate the price received or paid and, as appropriate, the relevant fully allocated costs or market values.
(c) Where fair market value is used, an explanation should be provided as to how the value was determined, including the comparative source for the value.
(d) Where cost allocations are involved, a description of the cost allocators and methods used to make the allocations should be included.
(e) A summary of corporate services and the methodology for ensuring fair allocations of these costs.

[3]Corporate support services are those Management and Administrative services which are provided to affiliates by NSPI. Examples include Board of Directors' costs, Public and Regulatory Affairs, Finance and Administration, Corporate Services, Legal, Human Resources and Information Technology.

7.2 NSPI shall submit an annual report to the Board by its external auditors, in a form satisfactory to the Board, which indicates whether the company is in compliance with the provisions of this Code of Conduct.

7.3 NSPI shall submit to the Board annually, all internal Code of Conduct implementation guidance along with a summary of significant interpretations or judgements made by NSPI related to the Code during the year.

7.4 In order to monitor compliance, the Board at any time may review the records of NSPI and, so far as is required for this sole purpose, the records of NSPI affiliates.

8.0 EMPLOYEE COMPLIANCE

Objectives

To ensure understanding of and compliance with this Code of Conduct.

Protocols

8.1 NSPI will inform all its managers and employees directly involved in affiliate activities of their expected behaviour relative to the Code of Conduct and will undertake annual management reviews to ensure compliance.

9.0 GENERAL

9.1 All reports referred to in this document shall be provided by April 30 in respect of each preceding year.

9.2 This Code of Conduct replaces the Interim Code of Conduct and shall become effective on January 1, 2005.

ORDER **NSUARB - NSPI-P-167**

IN THE MATTER OF THE PUBLIC UTILITIES ACT

-and-

IN THE MATTER OF AN INTERIM CODE OF CONDUCT to govern the relations between **NOVA SCOTIA POWER INC.** and its **AFFILIATES**

BEFORE: **Margaret A.M. Shears, Vice-chair**
Kulvinder S. Dhillon, P. Eng., Member
John A. Morash, C.A., Member

ORDER

WHEREAS Nova Scotia Power Inc. (NSPI) is a body corporate incorporated pursuant to the *Companies Act* and is engaged in the production and supply of electrical energy in Nova Scotia;

AND WHEREAS NSPI is a public utility and its business activities are regulated by the Nova Scotia Utility and Review Board (Board) pursuant to the *Public Utilities Act*;

AND WHEREAS NSPI is the principal operating subsidiary of, and is wholly owned by Emera Inc. (Emera), formerly known as NS Power Holdings Incorporated, a body corporate incorporated pursuant to the *Companies Act* on July 23, 1998;

AND WHEREAS Emera, by itself and through subsidiaries other than NSPI, has a number of business interests and engages in a number of business activities which are not subject to regulation under the *Public Utilities Act;*

AND WHEREAS on March 16, 2001, the Board issued an Order approving an Interim Code of Conduct which states, as its purpose:

> The primary purpose of this Code of Conduct is to ensure that the customers of Nova Scotia Power Inc. (NSPI) are not harmed by transactions between NSPI and its affiliates[4].

[4]For the purposes of this Code of Conduct, the term "affiliate" shall be interpreted in accordance with Sections 2(2), 2(3), and 2(4) of the Nova Scotia Companies Act.

AND WHEREAS PwC, in a report to the Board dated April 22, 2002, concerning the Interim Code of Conduct, had recommended changes to Section 4.2, the combination of Sections 6.1 and 6.3, and the addition of Section 6.11;

AND WHEREAS in consideration of submissions on the Interim Code of Conduct by NSPI and Intervenors during NSPI's 2002 general rate hearing the Board, in its decision, stated that:

> The Board finds that it is not appropriate, at this time, to give final approval to the Interim Code of Conduct. There appears to be merit to the suggestion that Article 1.1 of the Code be amended to require that affiliate transactions must demonstrate a benefit to NSPI ratepayers as opposed to causing them no harm. The Board intends to retain independent consultants to review the implications of such a change, and also to review the desirability of making further changes in light of the recommendations contained in the PWC report, the evidence presented at the hearing, and the findings of the Board in this decision.

AND WHEREAS PricewaterhouseCoopers LLP (PwC) completed its review of the Interim Code of Conduct and issued a final report to the Board in August of 2004, noting a number of recommended changes;

AND WHEREAS the PwC report was provided to NSPI on August 16, 2004, for its comments prior to the Board's final determination in this matter, which were filed by NSPI on October 22, 2004;

AND WHEREAS NSPI, in its submission of October 22, 2004, agrees with PwC's recommended changes to Sections 4.2; the combination of Sections 6.1 and 6.3; and the addition of Section 6.11 as outlined in PwC's report of April 22, 2002;

AND WHEREAS in its 2004 report PwC recommended the following revisions to the Code in order to facilitate the change in the primary purpose of the Code from ensuring that NSPI's transactions with its affiliates does "no harm" to its customers to ensuring such transactions "demonstrate a benefit" to NSPI's customers:

> **Changes to the Interim Code recommended pursuant to item 1.b.**
>
> Section 1.1: replace the words from "the customers" to "affiliates" with the words "transactions between Nova Scotia Power Inc. (NSPI) and its affiliates demonstrate a benefit to the customers of NSPI." (retain footnote 1 against the word "affiliates")
>
> Section 2.1: replace this section with the words "NSPI management will conduct the company's transactions with affiliates in such a way that its utility customers benefit from such transactions."
>
> Section 2.2: renumber as Section 2.3

Section 2.2: read as follows “NSPI’s customers will not otherwise bear the risks or share the rewards of an affiliate’s activities.”

Section 6.11: Replace the clause recommended in our April 22, 2002 report with “Before an activity is transferred from NSPI to an affiliate or from an affiliate to NSPI, NSPI must ensure there is a demonstrated benefit to its customers.”

AND WHEREAS PwC also identified the following issues in its August, 2004 report:

It must be made clear that, while we do not advocate the approval or disapproval of implementation guidelines, this is still essential information for the Board to utilize when reviewing compliance with the Code. The principles approach gives NSPI the responsibility for developing implementation guidance and, at least initially, applying its own judgements to inter-corporate transactions. However, this approach is only effective if these interpretations and judgements are reported or made available to the Board. This point seems to be fairly clear in Section 7.1 of the Code. The actual information filed by NSPI on April 30, 2003 does not, for example, comply with Sections 7(b), 7(c), or 7(d). As well, only part of the information required by Section 7(c) has been filed.

We do not recommend that the Board change the Code of Conduct to make the Guidelines subject to approval.

However, for clarity, we recommend the following amendment to the Code:

Renumber 7.3 to 7.4.
Add:
7.3 NSPI shall submit to the Board annually, all internal Code of Conduct implementation guidance along with a summary of significant interpretations or judgments made by NSPI related to the Code during the year.

and

The Code of Conduct section 7.2 indicates that “NSPI shall submit an annual report to the Board by its external auditors in a form satisfactory to the Board”. We recommend clarifying with NSPI that the Board expects that all items where judgement has been applied be disclosed as significant interpretations in this report, and, that these interpretations, where applicable, should refer to specific line items in the Affiliate Transaction Report. No changes to the Code are suggested as the above noted provision provides the Board with the ability to improve the current reporting.

As noted above, the Affiliate transaction information filed by NSPI on April 30, 2003 does not appear to comply with the reporting protocols in Section 7(b), 7(c), 7(d) or 7(e). This is not addressed in the audit report, the management letter or the summary of unadjusted differences.

Recommendation
We recommend that the Board request that NSPI re-file the NSPI/Affiliate Transaction Report and amend it so that it includes the information required by the Code of Conduct.

AND WHEREAS NSPI, in its October 22, 2004 submission, agrees with all but two of PwC's recommendations for revisions to the Code, stating that;

> NSPI is strongly opposed to the consultant's recommendation to replace the Code's current "no-harm" framework with a mandated benefit approach. ...

and

> ... We are opposed to the Consultant's recommendation that the Code be revised to require annual filings of the Guidelines. ...

AND WHEREAS the Board has carefully considered the reasons provided by NSPI for its objection to these changes but agrees with PwC when it states that:

> We conclude that both in terms of expectable normal business behaviour and in terms of NSPI's management intentions and practices, the replacement of the "no harm" criterion by a requirement that transactions must "demonstrate a benefit" would represent a reasonable amendment to the Code, which would not work a hardship on NSPI.

AND WHEREAS the Board agrees with PwC's recommended changes to the Code as outlined by PwC and the Board also agrees that NSPI should re-file its most recent Affiliate Transaction Report to include the information required by the Code of Conduct;

IT IS HEREBY ORDERED THAT the Interim Code of Conduct be revised in accordance with the recommendations of the 2004 PwC report and that the revised Code, attached as Schedule "A" to this Order, shall become the final version of the Code of Conduct, effective January 1, 2005.

IT IS FURTHER ORDERED THAT NSPI's most recent Affiliate Transaction Report be revised and re-filed, in accordance with PwC's recommendation, by March 31, 2005.

DATED at Halifax, Nova Scotia, this 9th day of November, 2004.

____
Clerk of the Board

Northland Utilities (Yellowknife) Limited, 2005/06 General Rate Application, Board Decision 12/2005

Northwest Territories Public Utilities Board

August 18, 2005

Ms. Judith Goucher
Director & CFO, Dept. of Finance
Northwest Territories Power Corporation
4 Capital Drive
Hay River NT X0E 1G2

Dear Ms. Goucher:

Re: Northland Utilities (Yellowknife) Limited 2005/06 General Rate Application

Enclosed is Board Decision 12-2005 dealing with all matters arising from the above-mentioned application.

Yours truly,

L. Larocque

Louise Larocque
Board Secretary

THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES

DECISION 12-2005 **August 18, 2005**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northland Utilities (Yellowknife) Limited for changes in the existing rates, tolls and charges for electrical energy and related services provided by Northland Utilities (Yellowknife) Limited to their customers within the Northwest Territories.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS	John E. Hill	Chairman
	Joe Acorn	Vice-Chairman
	Gene Nikiforuk	Member
BOARD STAFF	Louise Larocque	Board Secretary
	Raj Retnanandan	Board Consultant
	John Donihee	Board Counsel

APPEARANCES

Loyola Keough	Counsel for Northland Utilities (Yellowknife) Limited
Thomas Marriott	Counsel for The City of Yellowknife
Doug Ritchie	Program Director, Ecology North

WITNESSES

Northland Utilities (Yellowknife) Limited

Dennis DeChamplain	Vice President, Controller
Doug Tenney	General Manager
Ken Koenig	Senior Regulatory Analyst
Tony Martino	Senior Regulatory Analyst

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1. INTRODUCTION and APPLICATION

By letter dated December 31, 2004, Northland Utilities (Yellowknife) Limited ("**Northland**") submitted to the Northwest Territories Public Utilities Board ("**the Board**") a General Rate Application ("**GRA**", "**Application**") for the 2005/2006 test period ("**Test Years**") (Ex. 2).

In its Application, Northland requested that the Board:

a) Determine the Company's revenue requirement for each of the forecast test years 2005 and 2006;
b) Approve rate schedules;
c) Approve the revised Terms and Conditions of Service.

Pursuant to the provisions of section 13.(1) of the Rules of Practice and Procedure, the Board, by letter dated January 5, 2005 directed Northland to publish notice of the public hearing of the GRA in newspapers that circulate in the Northwest Territories. The notice provided details of the GRA and invited interested persons to file a request with the Board for intervenor status (Ex. 1).

The City of Yellowknife ("**the City**") and the Northwest Territories Power Corporation (**"NWTPC"**) registered their respective interventions with the Board. Ecology North of Yellowknife **("EN", "Ecology North")** indicated an interest in the proceeding, by letter dated January 26, 2005. The Yellowknife Chamber of Commerce also indicated an interest in the proceeding, by way of a fax dated January 27, 2005.

The Board and the City submitted information requests, to which Northland responded on or about March 4, 2005 (Ex 3).

Ecology North submitted a Proposal on March 9, 2005 seeking the Board's direction to Northland to institute an appliance rebate program **("ARP")** during the test period (Ex 5).

By letter dated March 10, 2005, Northland requested Board approval to proceed with a proposed meeting from March 16-18, 2005 to arrive at a Negotiated Settlement for Northland's 2005/2006 GRA. Northland identified the issues to be discussed at the negotiation meeting in the letter.

By letter dated March 14, 2005, the Board provided direction to Northland that the negotiated settlement should be confined to Phase I matters. Phase I matters involve the determination of the revenue requirements, forecast revenues and revenue deficiency/excess for the test years. Further the Board directed that should the negotiations result in a settlement on Phase I matters, Northland should refile affected portions of its Application reflecting the Settlement at a level of detail comparable to the Phase I filing.

A Comprehensive Phase I Negotiated Settlement ("**the Settlement**") dated March 24, 2005 was filed with the Board on March 31, 2005, together with letters of endorsement from all interested parties (Ex 6). By letter dated April 8, 2005, Northland refiled the affected portions of its application reflecting the Settlement. The revised rates also reflect corrections to the Franchise Tax allocation identified in information request YK-NUL-YK-25.

By letter dated April 11, 2005, the Board notified parties of a hearing to consider the Phase I Settlement and to consider Phase II matters involving rates, rate design and terms and conditions of service.

The Board submitted Information Request #2 to Northland respecting the Settlement, to which Northland responded on May 13, 2005.

The Board and Northland submitted information requests to Ecology North respecting its appliance rebate program proposal, to which Ecology North responded on May 13, 2005 (Ex 4).

2. PUBLIC HEARING

Public Notice of the hearing was published in the *Yellowknifer* on June 1, 2005 and in the *News/North* on June 6, 2005 (Ex 1). The hearing was held in the City of Yellowknife on June 22, 2005.

During the course of the hearing, members of the public who had not initially requested intervenor status were invited to participate in the proceeding.

Northland provided responses to the undertakings given at the hearing, at the conclusion of the hearing prior to the commencement of final submission by parties.

Final submissions were presented by Northland, the City and Ecology North. Northland presented reply submission to the submissions of other parties.

3. PHASE I NEGOTIATED SETTLEMENT

Northland filed for approval of the Settlement including approval of the revenue requirements of $27,827.000 for 2005 and $28,520,000 for 2006. Northland indicated that the Settlement was arrived at as a "package deal" between Northland and interested parties. The interested parties who are signatories to the Settlement are the City and NWTPC

The Settlement is attached hereto as Appendix A. The revised Phase I schedules, filed April 8, 2005, reflecting the changes agreed to in the settlement are attached hereto as Appendix B.

The following table provides a comparison of the rate base, revenue requirement, revenues at existing rates and revenue deficiency/excess as per the application and as per the Settlement:

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Utility Revenue Requirement
($000s)

Line No.	Description	per Application Forecast 2005	per Application Forecast 2006	Negotiated Settlement Forecast 2005	Negotiated Settlement Forecast 2006	Variance	
1	**Revenues**						
2	Retail revenues at existing rates	27,539	28,073	27,564	27,947	25	(126)
3	Other revenue	292	298	292	298	-	-
4	**Total Revenues**	27,831	28,371	27,856	28,245	25	(126)
5							
6	**Costs**						
7	Purchase power	22,163	22,572	22,185	22,414	22	(158)
8	Operations and maintenance	2,106	2,168	2,077	2,113	(29)	(55)
9	Taxes other than income	736	756	725	740	(11)	(16)
10	Amortization of deferred costs/credits	(54)	(54)	(54)	(54)	-	-
11	Depreciation	1,356	1,509	1,104	1,259	(252)	(250)
12	Amortization of contributions	(69)	(79)	(69)	(79)	-	-
13	Return on rate base	1,599	1,783	1,532	1,723	(67)	(60)
14	Income taxes	536	678	327	404	(209)	(274)
15	**Total Costs**	28,373	29,333	27,827	28,520	(546)	(813)
16	Revenue Deficiency/(Excess)	(542)	(962)	29	(275)	571	687
17	Rate Base	20,200	22,397	20,284	22,774	84	377

The Board has a statutory duty to regulate in the broad public interest. The negotiated settlement process must not fetter the Board's ability and discretion to take into account any public interest considerations, which may extend beyond the immediate concerns of the parties to the negotiations. If the Board is not satisfied that a Settlement is in the public interest, it must reject the Settlement.

In Sections 3.1 and 3.2, the Board will examine and comment on the individual components of the settlement and determine whether the settlement taken as a whole is fair and whether approval is in the public interest.

3.1. INDIVIDUAL COMPONENTS OF THE SETTLEMENT

3.1.1 Revenues

The adjustments to sales revenues resulting from the Settlement reflect corrections of certain errors in the residential and commercial sales volume forecasts in the original filing. These errors were identified in the responses to BR NUL YK 4 and BR NUL YK 5.

The Board's examination of forecast sales and revenues as per the Settlement has not resulted in any exceptions requiring further Board comment.

3.1.2 Purchased Power/Losses

The changes in purchased power costs reflected in the Settlement primarily reflect the changes in sales volumes referred to above.

One of the components of the cost of purchased power is line loss. Parties have agreed to set the line loss factor for 2005 at 6% and the line loss factor for 2006 at 5.8%. In its Application, Northland used a 5-year average of actual line loss percentages from 1999 to 2003 for the purposes of forecasting the loss factors. Northland confirmed discussions on the impact that the 25 kV distribution plant conversion project would have on line losses did take place during the negotiation process.

Response BR NUL YK 54 indicates the actual line loss factor for 2004 to be 4.33%. During hearing examination, the Board staff questioned Northland on why the 2004 actual line loss percent is materially less than the forecast for 2004. Northland indicated the lower line loss percent in 2004 is due to the impact of unbilled revenues in 2004. Northland indicated its methodology for recognizing unbilled was unchanged from prior years. (Tr., p.29) Northland also indicated it would not be appropriate to look at one single year for line losses but rather an average line loss should be looked at. In this regard, Northland stated as follows:

> "...it's difficult to take a look at any specific year and -- and use the line loss percentage number from that year as reflective of the correct line losses. I think you need to look at it in several years, so you can take more of an average.
>
> I think we've had a previous year, I think it was 2003, but I could be incorrect on that, where we had lower than normal line losses, likely because we had a higher unbilled number booked that year.
>
> And then the next year it reverses around and you end up with a bigger line loss number. So I think you need to really look at the average line loss. (Tr., p.33, *ll.*11-22)

Board staff questioned Northland on whether it expects line loss percentages to change as the proposed 25 kV distribution plant conversion project progresses into the future. Northland's witness responded as follows:

> "MR. DOUG TENNEY: As we've indicated in some of our Information Requests during this Proceeding, line losses are -- they're difficult to quantify, there may -- they take into account a number of issues, including the load. It takes into consideration the configuration, the number of lines or the kilometers of lines that are in service, as well as the voltage of those lines.
>
> But all of that said, so all those come into play, but generally, I would agree with your statement, that as the 25 kV project progresses, we would expect to see line losses decrease, especially if that was the only change, if there was no change in load or any other kilometers of line in service, et cetera." (Tr., p.35, *ll*.6-19)

The Board staff also questioned Northland on the level of line losses and the merits of benchmarking Northland's line losses against the best practices of other distribution utilities. In response, Northland stated as follows:

> "MR. DOUG TENNEY: Again, I -- we can benchmark, but I can't be -- I don't think anyone could guarantee that we're doing an apples to apples comparison, and to say that -- that the Yellowknife system should be at a 3 percent, if -- if ENMAX is -- is at a 3 percent.
>
> But, it is -- there's no denying that it is a significant portion of our costs, and so we should be striving to have all other things being considered, because there's always -- there's always capital costs associated or O&M costs associated with reducing line losses.
>
> But it's certainly something that we should be striving for." (Tr., p.38, *ll*.16-25 & p.39, *ll*.1-4)

In its final submission, Northland submitted it is very cognizant of the impact that line losses have on its situation and would continue to monitor line losses. Further, Northland submitted that the 6% line loss supported by the negotiated settlement is reasonable and should be accepted by the Board. (Tr., p.135, *ll*.12-17)

The Board considers the accurate forecasting of line losses to be important since changes in line losses and line loss factors can have a significant impact on Northland's earnings. The Board notes Northland's view that any single year line loss percent should not be used for purposes of the forecast. The Board also notes, should the 2004 actual be included in the average used to calculate forecast line loss percentages, the line loss percentages would be 5.6% in 2005 and 5.5% in 2006 as shown in the table below:

	Loss Factor Calculation Per Northland Application	Loss Factor Calculation Using Most Recent 5 Years Including 2004
1999	6.2%	
2000	6.2%	6.2%
2001	5.6%	5.6%
2002	4.8%	4.8%
2003	7.1%	7.1%
		4.3%
Average 2005	6.0%	5.6%
Average 2006	5.9%	5.5%
Source: BR NUL YK 8 and BR NUL YK 54c)		

If the additional 0.1% reduction in line losses resulting from the Settlement were reflected for 2006 the line loss percent for 2006 would be 5.4%. The Board estimates using the 5.6% for 2005 and 5.4% for 2006, based on the most recent 5 year average line loss percentages including 2004, would result in a reduction of $73,000 in 2005 and $74,000 in 2006 in the purchased power costs agreed to by the parties.

Having examined the foregoing, the Board has certain concerns with the loss factors implicitly reflected in the Settlement. First, the loss factors of 6% for 2005 and 5.8% for 2006 do not reflect the most recent actual data including the actual losses for 2004. However, the parties did not have the 2004 actual information at the time of the negotiations. Since the method of recording unbilled revenues did not change in 2004, the Board has no reason to believe 2004 recorded loss factor is an outlier. The Board is concerned that the line loss percent based on the most recent data is not reflected in the Settlement.

Second, the Board is concerned that the method of determining the annual loss factor, the level of which is driven largely by the amount of unbilled revenues at year end, may be causing fluctuations in the loss percent from year to year. The Board understands unbilled revenues at year end to result from cycle billings which the Board expects ought to be a relatively stable number from year to year subject to growth in unbilled.

The Board notes the 25 kV distribution plant replacement program commences in 2005 and will continue into 2012. Given the expected improvement in line losses resulting from the ongoing 25kV distribution plant replacement project, the Board expects the use of 5 year average line loss percentages for forecasting purposes could result in delaying or staggering any annual reductions from the 25 kV conversion project being fully reflected in rates. The absence of a transparent method for determining line losses for a given year with reasonable accuracy is a concern for future line loss determination. However, the Board infers from the 0.1% reduction in the 2006 proposed loss factor that parties appear to have addressed this issue as part of the Settlement for this GRA.

The Board will address the foregoing concerns respecting line losses in Section 3.2 of this Decision.

3.1.3 Operations and Maintenance (O&M) Expense

The Parties agreed to a reduction in O&M expense of about $29,000 or 1.4% in 2005 and $55,000 or 2.5% in 2006.

The Board's examination of the O&M expense component of revenue requirement as per the Settlement has not resulted in any exceptions requiring further comment.

3.1.4 Taxes Other than Income

Taxes other than income were adjusted for the impact of the Settlement on franchise fees.

The Board's examination of the taxes other than income component of revenue requirement as per the Settlement has not resulted in any exceptions requiring further comment.

3.1.5 Depreciation

The parties agreed that the amortization of the investment in existing substation equipment (account 477.10) and existing line transformers (account 479.10) being replaced by the conversion to a 25 kV system would be extended over 15 years as opposed to the 8 years initially proposed by Northland. Northland acknowledged this extension of the amortization period essentially reduces the impact of the retirement of the existing assets on customers.

The parties also agreed to change the amount for amortization of reserve differences for computer hardware (Account 483.20) and transportation equipment (Account 484.10). Northland provided the rationale for this change as follows:

> "MR. DENNIS DE CHAMPLAIN: The amortization of the differences when it exceeds -- when it exceeds ten (10) years we typically invoke amortization -- the amortization of differences.
>
> In our Application it did have an amortization of differences, even though it was under that ten (10) year threshold. I think they were two (2) and two point seven (2.7) years respectively. So, we removed that adjustment for the amortization as part of the negotiated settlement." (Tr., p.59, *ll*.2-11)

Northland noted, after the above adjustments, the method of amortizing reserve differences for accounts 483.2 and 484.10 will be consistent with that for other asset accounts. (Tr., p.60)

The Board's examination of the depreciation component of revenue requirement as per the Settlement has not resulted in any exceptions requiring further comment.

3.1.6. Return on Rate Base

The parties agreed to a common equity ratio of 39.60% in 2005 and 39.57% in 2006. Further the parties agreed to include consumer deposits in the capital structure. The parties also agreed to a return on common equity of 10% for each of 2005 and 2006. The Parties agreed that the forecast cost of debt will be reduced in each of 2005 and 2006. As a result of these changes, the return on rate base was reduced by $67,000 in 2005 and $60,000 in 2006.

The parties also agreed to deferral account treatment of the 25 kV conversion plant additions, as a risk mitigation mechanism. Northland described the mechanics of the deferral account as follows in its application:

> "The deferral account will be calculated by applying the before tax return on rate base percentages approved by the Board in this application to the total variation in the additions to the 25kV conversion project. In addition the variance on the depreciation expense as well as income taxes resulting from changes in the CCA on these additions will be included in the deferral account.
>
> Carrying costs on the outstanding balance in this deferral account will be applied at Bank of Canada rate plus 1.5%. This carrying cost rate is consistent with the EUB policy IL 2000-1 on interest rates.
>
> The carrying costs will be calculated on the outstanding balance in this deferral account and will commence on January 1 of the year following the year on which the before tax return was calculated. The carrying costs will continue until all amounts have been refunded to or recovered from customers. An application will be made by the end of the second quarter of the year following the year in which the before tax return was calculated to dispose of the balance accumulated in the deferral account. This will result in the first deferral account application on the 2005 test year taking place by the end of the second quarter in 2006.
>
> This deferral account will remain in place until Northland Utilities (Yellowknife) Ltd.'s next GRA application." (Ex. 2; p.7-11 & 7-12)

In its final submission, Northland submitted as follows with respect to the negotiated return on rate base:

> "...The negotiated settlement provides for a rate of return of 10 percent on a capital structure containing 40 percent equity.
>
> This is part of the package deal agreed upon by all parties, and should be viewed as such. NUL is aware of the fact that items such as rate of return, or return on equity, generally attract considerable attention in the context of normal or typical GRA's or GTA's.

> Here the Board can rely on the fact that it was part of the package deal as prima facie evidence of its reasonableness, that would be, as indicated this morning, something that is unique to the current circumstances and is not intended to be of a broader application.
>
> We're dealing here with a negotiated settlement, and it is something that was arrived at in the confines of that specific circumstance." (Tr., p.136, *ll*.9-25 & p. 137, *l*.1)

With respect to the proposed deferral account for 25 kV plant additions, Northland submitted as follows:

> "...The main issue discussed here was the new deferral account that has been approved with respect to the conversion program, the 25 kV conversion program.
>
> We would note that seldom has a situation arisen where a single project would have such a significant impact on the utility's rate base. The circumstances we are facing are indeed exceptional, and NUL submits that in the circumstances this deferral account is indeed appropriate, and warranted.
>
> The details of how this deferral account would work have been illustrated in the Undertaking Response 1 that has just been filed. NUL submits that its approach to a deferral account in this situation is reasonable, and should be accepted by the Board." (Tr., p.135, *ll*.19-25 & p. 136, *ll*.1-7)

The City expressed the view that the return on rate base reflects a reasonable compromise by the parties:

> " But if the Board does get into examining this specific element of the agreement in isolation which the City doesn't believe is necessarily appropriate, then it will be important, in our submission, that the Board consider that the agreement does reflect a significant reduction in the return on equity from what was originally filed, some seventy-five (75) basis points from what was originally proposed in The Application.

> Also, the Board should, in our submission, take into consideration, as Mr. Keough said, that historically there has been a recognized difference in risk between NUL and southern utilities and that that has been reflected in the rate of return that has been approved over the years as compared to southern utilities.
>
> And further, as Mr. Keough said again, NUL did file evidence that the Board can have reference to in -- in considering those differences. Taken in the context of that, the City is satisfied that the rate of return and equity thickness, taken together with the whole of the agreement, and that part is key, represents a reasonable compromise and, again, a balancing of interests of the Company and the customers for this -- for this application." (Tr., p.156, *ll*.7-25 & p.157, *ll*.1-5)

The Board notes Northland's view that the capital structure and rate of return reflected in the Settlement is unique to the current circumstances and is not intended to be of broader application. The return component of revenue requirement may therefore be considered part of the revenue requirement package. The Board considers if in subsequent years, the other components of revenue requirement were to change in relation to the return component; the latter in isolation may not be reflective of a fair return. Considering the likely changes in the relative proportions of various components of revenue requirement that can occur over a period relative to the Settlement, the Board considers that the composite rate of return resulting from the Settlement, taken in isolation, may not be reflective of a fair return to be used in the calculation of the 25 kV conversion deferral amounts, once the two test years have been completed. Accordingly, the Board will be concerned if the 25 kV deferral account mechanism were to continue beyond the two test years.

The Board will address this concern in Section 3.2 of this Decision

3.1.7 Income Taxes

The parties agreed to reflect the CCA rates as proposed in the February 23, 2005 Federal Budget in the income tax calculations with the proviso that if the reduced rates are not officially enacted the negotiated settlement will be automatically amended to reflect the change in the approved revenue requirement. The parties also agreed that if Northland claims and the Canada Revenue Agency ("**CRA**") has accepted any income tax deductions for 2005 or 2006 arising from the expensing of costs that have been capitalized for regulatory purposes the benefits of such deductions will be flowed through to customers. Further, if there is a subsequent reversal of such deductions by the CRA the benefits previously flowed through will be reversed.

The Board's examination of the income tax component of revenue requirement as per the Settlement has not resulted in any exceptions requiring further comment.

3.1.8 Rate Base

The rate base reflects the adjustment for reduction in depreciation expense referred to previously. The Parties also agreed $140,000 pertaining to study costs related to the 25 kV conversion project will remain in construction work in progress in 2004 and will be capitalized in 2005.

The Board's examination of the rate base as per the Settlement has not resulted in any exceptions requiring further comment.

3.2 THE SETTLEMENT TAKEN AS A WHOLE

In this Section, the Board will evaluate the comments of the parties as well as the Board's comments in the preceding section dealing with individual components of revenue requirement, in light of the Settlement taken as a whole.

Northland submitted overall the Settlement is in the public interest:

> " The City of Yellowknife was represented in these proceedings, or in these discussions, by experienced counsel and regulatory consultants. NUL submits that the Board can, and indeed should take great comfort in the fact that the end results that were achieved via these negotiated settlement discussions were acceptable to all the participants.
>
> The Board is essentially being called upon to accept the negotiated settlement as a package deal, and not to focus on any one (1) specific component of the overall deal. This essentially requires the Board to conclude that, overall, the negotiated settlement is in the public interest." (Tr., p.133, *ll*.4-16)

Northland also submitted that the Board can, and should look to the knowledge, experience, and information that the parties had available to them, and conclude that the Phase 1 negotiated settlement is indeed persuasive evidence of its reasonableness, and the results contained therein. (Tr., p.133, *ll*.20-25)

Northland noted that the Board has other information available that can be used to test the reasonableness of the Settlement. (Tr., p.146, *ll*.14-20)

The City submitted significant reductions in the revenue requirement were achieved in the Settlement especially if one looks at the revenue requirement excluding purchased power. In this regard, the City stated:

> " The result, sir, was the agreement which has been filed with the Board and which delineates, in the City's submission, significant reductions in the revenue requirement as set out in the original application, especially when one removes the cost of power from the revenue requirement, and looks only to the portion of revenue requirement that the Company has control over.
>
> The agreement is the product of serious negotiating, gives and takes, and the City supports the position that it should be approved as a package including all aspects: depreciation, line losses, rate of return, the entire package." (Tr., p.152, *ll.*19-25 & p.153, *ll.*1-6)

The Board notes reductions of 9.1% in 2005 and 9.7% in 2006, in the non purchased power component of revenue requirement were achieved as a result of the Settlement. The Board notes the major portion of the reduction resulted from reductions to the depreciation expense and the consequent impact of the depreciation reduction on income tax. Nevertheless, the Board agrees with the City that significant reductions in the revenue requirement were achieved in the Settlement especially if one looks at the revenue requirement excluding purchased power.

The Board notes adequate notice was provided and no party opposed the Settlement. The Board considers therefore that the Settlement process was fair. The Board also notes from its examination of the individual components of revenue requirement that the substantive issues in the Application were addressed by the parties. The Board concludes therefore the Settlement taken as a whole can be considered to be in the public interest subject to the following.

In examining the individual components of revenue requirement certain concerns were identified by the Board with respect to loss factors resulting from information that came to light after the Settlement was concluded. In particular the 2004 actual loss factor, if reflected in the 5 year average, would result in a material reduction in purchased power costs which in turn can impact the balance arrived at by parties in regard to the non purchased power component of revenue requirements for 2005 and 2006. Since this information came to light after the Settlement was concluded, the parties to the Settlement could not have been aware of this information.

Accordingly, the Board directs Northland and the other parties to the Settlement to reassess the level of loss factors for 2005 and 2006 in light of the new information provided in response BR NUL YK 54 with respect to the 2004 actual loss factor and the impact of including this in the 5 year average for loss factors. Amendments to the Settlement, if any, resulting from these discussions should be included as part of the refiling of the Application. The Board will defer consideration of the Phase I Settlement and approval thereof until this reassessment has been completed. Likewise the Board will defer any directions respecting implementation of the Settlement until the reassessment is completed.

In addition to the foregoing, the Board expressed other concerns in Section 3.1 when examining the individual components of revenue requirement. The Board's directions or comments in this regard follow.

The Board expressed concern that the method of determining the annual loss factor, the level of which is driven largely by the amount of unbilled revenues at year end, may be causing fluctuations in the loss percent from year to year with consequent impact on earnings. The Board also expressed concern that the absence of a transparent method for determining line losses for a given year with reasonable accuracy is a concern for future line loss determination.

In order to address these concerns, Northland is directed to develop procedures for determining actual line loss factors for each year, which are reasonably reflective of the electrical line losses for that year. To the extent the unbilled consumption is a factor amongst others causing fluctuations in overall loss factors from year to year, the percent loss factor applicable to electrical losses should be identified separately from the loss factor applicable to other factors under the category of unaccounted for losses. Northland should institute the above procedures with immediate effect and explain how these procedures address the accurate determination of forecast loss factors, at the next GRA.

Northland is also directed to provide a comparison of forecast electrical loss factors with those that were anticipated at the time of the 25 kV conversion application, with explanations for differences, at the time of the next GRA.

The Board expressed the view that it will be concerned if the 25 kV deferral account mechanism were to continue beyond the two test years and the rate of return resulting from the Settlement were used to be used to make adjustments to the 25 kV capital deferral accounts beyond the test period. Accordingly, if Northland intends to continue the 25 kV deferral account mechanism beyond the 2005/2006 test period it should take steps to initiate a GRA on a timely basis.

3.3 ECOLOGY NORTH PROPOSAL

As a pilot project, Ecology North requested funding approval for an appliance rebate program for Northland customers who purchase certain Energy Star qualified appliances. EN proposed that this program be funded by Northland and be managed by Ecology North. Under EN's ARP proposal rebates of $100.00 for fridges and $50.00 for washing machines will be paid to appliance owners who exchange their existing appliances for energy star qualified appliances. EN estimated the uptake from the rebate program administered over a 12 month period during the 2005/2006 test period would be 400 customers under the fridge replacement program and 400 under the washing machine replacement program.

EN stated information on the program would be made available at each appliance store in Yellowknife. EN stated in order to access the rebate, consumers would have to prove:

- that they are Northland customers;
- that they have purchased an Energy Star qualified appliance; and,
- that they have sent their old appliance for recycling.

EN summarized the expected overall benefits of the program as follows:

> "In conclusion, we believe that the proposed Appliance Rebate Program would lead to significant short and long-term gains in energy conservation. The program should help reduce water consumption (and heating), and by reducing pressure on peak demand and energy growth, it should reduce the reliance on the Jackfish Lake generating plant and the attendant greenhouse gas emissions. An equally important impact will be an increased awareness of energy conservation amongst Northland customers, local property managers, and the City of Yellowknife. We believe that this increased awareness will be critical for gaining support for even more effective energy conservation measures such as time-of-use(smart) metering." (Ex. 5; p.8)

EN also proposed that Northland research the introduction of smart meters and time of use meters in the Yellowknife service area. EN stated starting the gradual introduction of smart meters could help to offset a much larger capital cost down the road. EN noted some brands of smart meters allow customers to pay in advance and monitor how much electricity they have consumed in dollar terms. EN stated, to be effective as possible and to justify the expense, smart meters need a time of use price structure. EN noted that with variable pricing there is an opportunity to reduce peak demand. Reduced rates during off peak hours can help economic development or replace fossil fuels. EN requested the Board to direct Northland by way of a directive similar to the one given in Decision 3-2003 for NWTPC with respect to the implications of time of use rates and time of use meters on the Northland system and report back to the Board preferably at the same time as NWTPC.

In response to BT EN 4 (a), EN acknowledged, based on NWTPC's estimates, the greenhouse gas emissions savings for the ARP would effectively be zero. However, EN argued ARP and other demand-side management measures, will help consumers reduce their electricity bills and will help to postpone the need to increase diesel generation at Jackfish as Yellowknife grows. EN noted that in diesel communities, an ARP and demand-side measure would most likely result in greenhouse gas emission savings.

With regard to the EN proposal, the Settlement states in part as follows:

> "..should the Board decide to approve an addition to the negotiated revenue requirement, as derived pursuant to this agreement to facilitate an appliance rebate program similar to that advanced by Ecology North in these proceedings, the negotiated revenue requirement shall be automatically adjusted to include such an amount for 2005 and 2006 as is approved by the Board." (Clause 3 of Settlement, p.4)

In its final Argument, Northland submitted it is sympathetic to the efforts of EN but questioned whether the Board is the appropriate forum to consider some of the EN proposals:

> " In the context of Ecology North's proposal, we would note that certain of the -- or we would -- would observe, I suppose, that certain of

> the discussions regarding various aspects of the proposal, appear to have gone far afield of what this Board probably can and should legitimately do, and get involved in. And that's another consideration that you may want to take into account when examining this matter.
>
> This Board's jurisdiction may well enable you to approve the inclusion of an amount in revenue requirement to be dispersed, as per the Ecology North proposal. But I think you must be cognizant of where your jurisdiction ends, and there are many aspects that have to be worked out in the details of such a program that may well be beyond your grasp. And some of those things came up this morning." (Tr., p.144, *ll*.3-18)

With regard to EN's proposal concerning smart meters, Northland stated:

> " Now, there was also discussion of the Smart meters, and again, we've tried to update the Board with regard to the pilot program that ATCO Electric has implemented.
>
> We're not sure that that is really the subject matter of these proceedings. We understand it's an issue that, albeit belatedly, was raised by Ecology North, but we really aren't sure that there's anything in this proceeding that you're being asked to do.
>
> There was some discussion about the NWTPC's program and I think Mr. Tenney indicated that NUL would be prepared to engage in these discussions as well, with a view to gaining some appreciation as to whether or not these type of programs can be legitimately conducted within Yellowknife.
>
> And I -- I think that commitment is probably all that's required here, if -- if even that's required. We do not think that the Board need make any specific decision or ruling with regard to what NUL should do." (Tr., p.145, *ll*.1-20)

Mr. Doug Ritchie for EN submitted, EN is not tied to any particular DSM program but considered the ARP program proposed by EN is a good one:

> " So I think there's a real rationale, we think, for the Board to intervene and say, hey, let's try to take advantage of some savings right now in terms of energy use. Let's take some steps towards moving towards a situation where five (5), ten (10) years down the road we say, oh, Yellowknife's grow -- growing and all of a sudden we have a large diesel generating plant, or a large hydro-electric facility that we have to deal with.
>
> We may not be able to avoid that, but at least by taking actions now to try to restrain demand, we can try to push back the date for those facilities. And with respect to the whole issue of demand side management, we -- we're not tied to any particular program, although we think the ARP, the Appliance Rebate Program, is a good one." (Tr., p.149, *ll*.20-25 & p.150, *ll*.1-9)

The City stated EN amended its ARP proposal in response to BR EN 5, where the rebate amount for both types of appliances was amended to $75.00 each.

The City also submitted it is within the Board's jurisdiction, to consider the public interest and that it is in the public interest to conserve energy where possible and reasonable and it is in the public interest to potentially delay the need to add diesel generation or any other form of generation. Therefore, the City supported the ARP program with the above noted amendment. In this regard, the City stated:

> "...The City of Yellowknife supports the rebate program as set out in Exhibit 5. And as we understand it, as amended in Board/Ecology North-5. So amended to seventy-five dollar ($75) rebate for both types of appliances.
>
> As the City understands it, the reason for the differential as explained in the original proposal was that the energy savings for fridges wasn't as dramatic as it was for washing machines and thus it was felt that extra incentive was needed to incent consumers to make the switch to fridges.

But as the City understands the answer to Board/Ecology North-5 now, Ecology North has now considered that the difference in cost between an energy efficient washing machine and a non-energy efficient washing machine is considerably greater than the difference between fridges in those categories, which leads to the conclusion that the rebate perhaps should be seventy-five dollars ($75) for both appliances. The City can accept that reasoning.

The City does believe that it is within the Board's jurisdiction, certainly, to consider the public interest and that it is in the public interest to conserve energy where possible and reasonable and it is in the public interest to potentially delay the need to add diesel generation or generation at all for that matter. For those reasons the City does support that proposal.

For similar reasons, the City would support the Board issuing a directive to NUL to report on Time Of Use Meters and their feasibility in this jurisdiction in an effort coordinated with NTPC. I don't think the City would support going any further than that.

I think that's what Ecology North has asked for. They haven't asked for implementation. They've merely asked for that study and report." (Tr., p.162, *ll*.20-25 to p.164, *ll*.1-5)

The Board notes, EN requested a one time funding of $75,000 for the ARP program, to be administered and paid out over a period of 12 months during the test period. The Board notes Northland's position that customers would decide to what extent they conserve energy based on the price signals reflected in rates.

The Board notes the City's view that it is within the Board's jurisdiction, to consider the public interest and that it is in the public interest to conserve energy where possible and reasonable and it is in the public interest to potentially delay the need to add diesel generation or any other form of generation.

The Board considers that any demand side management project approved by the Board must make economic sense from a cost benefit point of view. Accordingly, the Board is prepared to consider the proposed ARP based on its merits as a viable demand side management project.

The Board notes the greenhouse gas emissions savings for the ARP in the Northland service area would effectively be zero. Irrespective of the level of greenhouse gas emission savings, the Board does not consider it within its jurisdiction to consider the merits of the project on the basis of greenhouse gas emissions savings.

The costs and estimated benefits, in terms of value of energy savings, of the ARP, as calculated from information provided by EN are as follows:

Program Component	**One Time Program Cost**	**Net Present Value of savings**	**Benefit/Cost**
	$	$	$
Fridge Rebate	50000	54013	1.08
Washing Machine Rebate	25000	281400	11.26
Total	75000	335413	4.47

Source: X 4 Updated Tables 2 & 3 BR EN 5(b)

The Board notes EN's view that by taking action now to try to restrain demand, the date for additional supply facilities and distribution facilities may be pushed back. In the Board's view given the estimated overall benefit cost ratio of more than 4 times noted above, the ARP proposal may be expected to provide benefits to all customers of Northland by delaying new facility additions at a lower cost than if the facilities were added absent the ARP.

The Board recognizes this is a pilot program and the estimated benefits may or may not materialize. However, the Board notes EN's view the proposed ARP could be considered a seed program potentially triggering higher levels of uptake for energy efficient appliances.

Considering the foregoing, the Board concludes the ARP is a viable demand side management program. Accordingly, the Board will approve the ARP with the amendment to the rebate levels as noted by the City.

The Board considers the ARP should be administered by Northland either directly or through contract with an organization such as EN. The Board directs Northland to file a proposal for initiating, administering and reporting on the delivery and success of the ARP including details of how the eligibility requirements for rebates noted by EN would be implemented, as part of the refiling of the Application.

With respect to rate treatment of the cost of the ARP, the Board notes Northland's submission that the costs should be recovered by way of a rate rider and adjusted to actual in 2007

> "It is difficult to forecast the actual number of participants in this program if it is approved. As such, there should be a mechanism in place to ensure equitable treatment for customers and the company. However, in light of the fact that the energy component of the retail rate and the purchase power rate are close to the same value, NUL-YK believes that for the sake of simplicity that only the administrative and rebate components of the program should be based on a reasonable forecast of participation and administered through a rate rider rather than base rates. The difference between the forecast administrative and rebate costs and the actual costs should be collected in a deferral account and refunded/charged to customers through an adjustment to the rider. The adjustment to the rider would occur in the following year allowing termination of the rider at the end of 2007." (BR NUL YK 65)

The Board considers the Northland proposal for rate treatment as outlined above to be reasonable and accordingly, directs the company to file a proposed rate rider with respect to the ARP as part of the refiling of the Application.

The Board considers the ARP as a demand side management program is expected to benefit all customers of Northland. Accordingly, the cost of the ARP should also be borne by all customers. The Board therefore directs Northland to design the ARP rider to be applicable to all customers of Northland, in its refiling of the Application.

With respect to EN's request that Northland investigate the implications of time of use rates and time of use meters on the Northland system, the Board agrees that it is appropriate to provide the right price signals to customers that would result in delaying new plant additions. Accordingly, the Board to directs Northland to investigate the benefits and market potential for time of use rates and address this matter at the time of the next GRA.

The Board also notes EN's view that some brands of smart meters allow customers to pay in advance and monitor how much electricity they have consumed in dollar terms. During the hearing, Northland indicated that its parent, ATCO Electric Limited had instituted a pilot program for smart meters in the communities of Grande Prairie and Drumheller, Alberta. The Board directs Northland to report on the lessons learned from this pilot program and address the applicability of these lessons in the Northland service area, at the time of the next GRA.

4. PHASE II MATTERS

4.1 COST Of SERVICE STUDY

4.1.1 Tracking of Customer Contributions

Northland indicated contributions in aid of construction (less amortization) were allocated to rate classes based on gross property plant and equipment. Northland indicated contributions are not tracked by rate class. In BR NUL YK 36(b), the company was questioned as follows:

> "Given the different maximum investment levels of different rate classes, please comment on the appropriateness of allocating contributions on the basis of gross plant as opposed to direct assignment or any other method that approximates direct assignment (example: sampling)."

In response Northland stated:

> "The allocation of contributions on the basis of gross plant is reasonable in these circumstances. Other methods, such as sampling, would not be reliable as contributions are not consistent from one year to the next or from one project to the next. The direct assignment method would be most accurate; this method, however, would entail a time consuming approach involving the study of all historical invoices." (BR NUL YK 36(b))

In its final submission, Northland indicated it is prepared to track contributions by rate class in the future and to assess the ability to look at historical contributions by rate class:

> " As indicated during Board questioning, NUL is -- is amenable to tracking contributions by rate class in the future, and will indeed assess the ability to look retroactively for a number of years, which obviously will

depend upon the availability and condition of records for those past periods." (Tr., p.139, *ll.*14-19)

Given the different maximum company investment levels applicable to different rate classes, the Board considers tracking of contributions by rate class would enhance the accuracy of the cost of service study. The Board notes Northland's willingness to track future contributions by rate class and to assess the ability to look at historical contributions by rate class. The Board considers tracking of historical contributions is a desirable objective to the extent it would have a material impact on the cost of service by rate class. However, the costs of such an exercise should be weighed against this benefit. Accordingly, the Board directs Northland to begin tracking future contributions by rate class, commencing with the beginning of the 2005 test year. Northland is also directed to assess the tracking of historical contributions having regard to the costs and the benefits and to reflect or report on the outcome at the time of the next GRA.

4.1.2 Classification of Demand Component of Purchased Power Costs

Northland classified the demand component of purchased power costs to energy in its cost of service study. Northland considered it would be suitable to classify the demand component of purchased power costs on the basis of demand. However, Northland argued against switching only one component without a complete analysis of all aspects of its cost of service and rate design. (Tr., p.140-141) Northland also noted there is more than one component to the rate design and one or the other would need to be changed if the classification of the demand component of purchased power costs were changed. (Tr., p.166)

The City disagreed with Northland and submitted the change should be made in these proceedings as it is an obviously fairer method of allocation:

> " And while the City can appreciate and understand that position, it believes that this obvious change should be made now as it simply appears to be obviously fairer than the method proposed.
>
> Certainly the City does not oppose a more thorough or comprehensive review at the next GRA, in fact, would welcome that." (Tr., p.161, *ll*.6-12)

The Board notes from response BR NUL YK 39 c) that a change in the classification of demand component of purchased power costs from the proposed energy classification to a demand classification would result in the following impacts by rate class:

Northland Utility (Yellowknife) Limited
Impact on Costs
Classifying Portion of Purchase Power to Demand

	Original Costs ($000)	Revised Costs ($000)	Incr/(Decr) Costs ($000)	Incr/(Decr) %age
Residential	11,193.4	11,492.4	299.0	2.7%
General Service	16,144.6	15,833.8	-310.8	-1.9%
Street Lights	727.3	738.6	11.3	1.6%
Space Lights	15.4	15.9	0.5	3.2%
Total	28,080.7	28,080.7	(0.0)	0.0%

The Board notes Northland's submission that this issue should not be viewed in isolation without a complete analysis of all aspects of the cost of service and rate design. The Board also notes Northland's view that changing the classification of purchased power costs could impact one or more components in the exercise of rate design.

The Board considers the classification of the demand component of purchased power costs on the basis of demand is reflective of cost causation. Although there may be other refinements to the filed cost of service study which may have an impact on costs by rate class the specific impacts of those refinements have not been identified or examined in these proceedings. The Board is not persuaded by the argument that it should not reflect an identified cost causation principle in the cost of service study for the reason there may be other potential changes. The Board recognizes a change in classification of the demand component of purchased power costs could impact the costs considered as fixed or demand related in the rate design exercise. However, the Board considers the impact of a change in the classification is one among many other factors to be considered in rate design. The Board will discuss this issue in the rate design section.

In view of the foregoing, the Board considers it appropriate to change the classification of the demand component of purchased power costs to a demand classification. The Board directs Northland to change the classification of the demand component of purchased power costs to a demand classification in its refiling of the Application.

4.1.3 Account Classification Factors

Northland proposed the following account classification factors for distribution assets:

Description	Customer Related	Demand Related
Land	0%	100%
Land Rights	0%	100%
Structures and Improvements	0%	100%
Poles Towers and Fixtures	75%	25%
Overhead Conductors	30%	70%
Services	100%	0%
Substation Equipment	0%	100%
Line Transformers	30%	70%
Meters and Meter Equipment	100%	0%
Street Loghts	100%	0%
Space Lights	100%	0%

Northland indicated it had not carried out a recent review of the above account classification factors. Northland indicated given the significant time lapse since these factors were last reviewed, it would be appropriate to review them having regard to the costs and benefits of conducting studies. In this regard, Northland stated:

> " The balance to be achieved here, particularly in the context of a small utility such as NUL, is one of a cost benefit assessment. NUL is willing to commence such a -- a review if the Board deems it to be necessary or appropriate, but we must always be cognizant of the associated costs.
>
> Clearly such studies should not be undertaking without a great deal of thought, and only when it -- it is expected that the benefits will exceed the costs, at least in the long run. As stated by NUL, any study should be complete, and at least we'll get all accounts and not be overly selective in nature." (Tr., p.140, *ll*.3-14)

The Board agrees it would be appropriate to carry out a study of account classification factors having regard to the costs and benefits involved in conducting such a study. Accordingly, the Board directs Northland to review all classification factors to determine if they remain appropriate and to reflect the results in the next Phase II application. The scope of the study should bear in mind the costs involved in conducting the study and the benefits in terms of enhancing the accuracy of cost classification and allocation by rate class.

The Board will accept the account classification factors proposed by Northland for purposes of these proceedings.

4.1.4 Classification of Administrative and General

Administrative & General ("**A&G**") expenses were classified by Northland on the basis of the sum of all service costs, including revenue offsets but excluding public liability and public damage insurance costs (PLPD) as shown in Schedule 11.15 of the cost of service study. The service costs for purposes of this classification included purchased power costs. As a result of including purchased power costs in service costs, a portion of A&G expense was classified as energy related and allocated to rate classes on the basis of energy.

The City questioned the proposed classification and allocation of A&G expense on the basis of service costs that included purchased power costs. In this regard, the City submitted:

> "...The City believes that there is no real logical link between purchased power and the administration and general costs and, on reflection, if fuel costs doubled, in our view, that should not change the quantum of NUL's administration and general costs.
>
> Accordingly, the City would propose that NUL recalculate the response to YK-NUL-YK-24(B)using the revenue requirement approved by the Board and that the allocation be made on the basis of all costs

excluding purchase power and administration and general PL and PD." (Tr., p.159, *ll*.13-23)

The Board estimates the change in classification of A&G expense proposed by the City would result in the following approximate increase or decrease by rate class:

	Original Costs	A&G classified on all costs including purchased power costs per Northland	A&G classified on all costs excluding purchased power costs per City	Approximate Increase/(decrease)	Approximate Increase/decrease Percent
	$000	$000	$000	$000	
Residential	11193.4	179.1	281.5	102.40	0.9%
General Service	16144.6	317.4	174.2	(143.20)	-0.9%
Street Light	727.3	4.7	45.4	40.70	5.6%
Space Light	15.4	0.2	0.4	0.20	1.3%
	28080.7	501.4	501.5		

The Board notes, from the above table, the order of magnitude change in costs by rate class is significant. The Board considers the classification of A&G expense should reflect cost causation. The Board agrees with the City that there is no logical link between A&G expense and purchased power. Accordingly, the Board is prepared to accept the City's proposed classification of A&G expense on the basis of all service costs excluding purchased power costs, A&G expense and PLPD, as this would be consistent with cost causation. The Board directs Northland to classify A&G expense on the basis of all service costs excluding purchased power costs, A&G expense and PLPD, in its refiling of the Application.

4.1.5 Energy Weighting of Metering Assets

Northland classified metering asset costs to the customer category and the customer costs associated with meters were further weighted to reflect the meter costs for customers in different rate classes. As well, 2% of the metering assets were weighted by relative energy supplied. Northland indicated these weightings are in accordance with previously approved methodologies.

In response BR NUL YK 38 (c), Northland acknowledged the weighting of 2% of metering assets by energy is in error and will be corrected. (Tr., p.90, *ll.*10-22)

The Board considers a 2% energy weighing for meter assets is not appropriate given the initial weighting to reflect differences in meter costs by customer class. Accordingly, the Board directs Northland to remove the 2% energy weighting of meter assets in its refiling of the Application.

4.2 RATE DESIGN/REVENUE TO COST RATIOS

Northland stated the following rate design criteria were relied upon to design the proposed rates:

- Recover the total forecast revenue requirement.
- Utilize the cost of service allocations of the revenue requirement.
- Avoid undue discrimination between customer classes.
- Consider the rate levels, structures and policies of other utilities, particularly those of similar load and service conditions.
- Promote ease of understanding and acceptance by customers, as well as ease of administration and economy of billing.
- Recognize the level and structure of existing rates.
- Promote efficient and cost effective use of power through price signals built into the rate structure. (Application, p.12-1,12-2)

Northland stated it is attempting to move the revenue to cost ratios for each class into the range of 95% to 105% subject to the constraint the increase decrease for any one rate class is less than 10%.

Northland proposed the following revenue to cost ratios under proposed rates:

	2005	**2006**
Residential	95%	95%
General Service	103%	103%
Street Light	101%	100%
Space Light	100%	99%

Northland suggested there should be flexibility in establishing revenue to cost ratios for different classes given the lack of precisions inherent in any cost of service study. In this regard, Northland stated:

> " There are many assumptions built into both cost of service and rate design, that render the achievement of a specific target, like 100 percent, to be something that is really not as precise as it may seen.
>
> In reality, a range, such as 95 to 105 percent, is far more reflective of the circumstances that do, in fact, exist. And in addition, provide flexibility to the utility that it needs to address various situations that confront it on an ongoing basis.
>
> We would urge the Board to recognize the desirability of retaining this type of flexibility, and not to get caught up in trying to achieve a single 100 percent revenue to cost ratio for all classes." (Tr., p.141, *ll.*11-23)

Northland noted the rate increases to the residential class were kept to a minimum to minimize rate impact as a result of this GRA and having regard to any potential future increases.

The City submitted the proposed 95% revenue to cost ratio for the residential class is reasonable having regard to the fact that there has been an improvement since the last GRA and having regard to the cost of service changes proposed by the City in these proceedings:

> " If we look back in the decision on the 1996/97 GRA the Board, at that time, approved a revenue to cost ratio for domestic at 92.5 percent in 1997. So in this next application we have already moved to 95 percent and the City would consider that that is a reasonable step rather than going to the full 100 percent which we believe would be a significant impact on residential customers.
>
> And further, as I've mentioned and as you will hear more about, the City will propose two (2) changes in the allocation of costs both of which have the general effect of shifting cost from the general class to the domestic class.
>
> The City is advocating that these changes be made and that the revenue to cost ratio for the domestic class be maintained at 95 percent. Thus, the domestic rate would go up from what is presently proposed and the general rate would go down correspondingly." (Tr., p.157, *ll*.24-25 & p.158, *ll*.1-16)

Northland appears to defend its proposal to target a residential class revenue to cost ratio of 95% on the basis that the cost of service study is not precise. The Board recognizes the cost of service study is not an exact science as it includes many assumptions but does not agree this reason alone justifies a target revenue to cost ratio less than 100% for any one rate class. The Board considers, notwithstanding its limitations, the cost of service study provides the best estimate as to costs by rate class. Accordingly 100% should remain the target revenue to cost ratio for all rate classes subject to other rate design considerations.

In Section 4.1 dealing with the cost of service study, the Board determined there should be certain changes to the cost of service study and directed Northland to reflect these changes in the refiling of the Application. As noted by the City, the principal changes involving the classification of the demand component of purchased power costs and the classification of A&G expense have the general effect of shifting costs from the general service class to the residential and other classes. Accordingly, in the interest of mitigating rate impacts, the Board will accept a revenue to cost ratio of 95% for the residential class, for the purposes of these proceedings. The Board directs Northland to design rates in accordance with these findings, subject to the constraint the increase/decrease for any one rate class is less than 10%, in its refiling of the Application.

4.3 INDIVIDUAL RATES

4.3.1 Domestic (Residential) Rate

Northland proposed to increase the existing residential Customer Charge to $18.00 from $15.00 to bring it in line with neighbouring utilities, and proposed to increase the energy charge to 14.28 cents/kW.h.

Northland indicated, based on the cost of service study the average customer related cost is approximately $27 per customer per month. The movement of the customer charge to $18 brings the customer charge closer to the customer related costs taking into consideration other rate design criteria. (BR NUL 43 (a))

The City supported the proposed upward movement in the residential fixed charge and considered any further upward movement in the fixed charge towards full cost recovery would not be conducive to conservation:

In this regard, the City stated:

> " For that reason, the City would submit that the eighteen dollar ($18) -- the movement to eighteen dollars ($18) is reasonable. It's a movement

> towards cost causation but we would submit that the conservation angle also has to be considered." (Tr., p.155, *ll*.20-24)

The Board notes the proposed residential fixed charge would recover approximately 67% of the customer costs associated with residential service. The Board recognizes this percentage cost recovery may be somewhat lower with the changes to the cost of service accepted in this Decision, though not materially so for the purposes of rate design. The Board notes, the submissions of Northland and the City, that this level of recovery strikes a reasonable balance between cost recovery and other rate design criteria. The Board agrees with the views of Northland and the City in this regard. Accordingly, the Board will accept the increase in the residential fixed charge from the existing $15 per month to $18 per month as proposed by Northland. The Board directs Northland to reflect a residential fixed charge of $18 per month in the refiling of the Application.

4.3.2 General Service (Commercial) Rate

Northland proposed to increase the minimum billing demand for commercial customers to 5 kV.a from 2.4 kV.a (equivalent to the $20 minimum monthly charge at $8.20 per kV.a) to reflect a similar bill minimum of neighbouring utilities. Northland also proposed to reduce the general service demand charge to $7.36 per kV.a from the current $8.20 per kV.a and proposed an energy charge of 12.80 cents/kWh.

With regard to the rationale for the proposed changes, Northland stated as follows:

> "NUL YK has attempted to move the rate components of the General Service rate class towards 100% revenue-to-cost ratios. As a result, the proposed demand charge of $7.36/kV.a is close to the COS calculated

> cost of \$7.70/kV.a taking into consideration other rate design criteria. NUL YK's customer related cost to provide service to General Service customers, is \$43.34/customer/month. NUL YK proposes a minimum demand level of 5 kV.a, which is equivalent to a minimum charge of \$36.80/customer, to recover 85% of the cost." (BR NUL YK 44 (b))

The Board notes Northland's attempt to more closely match the demand and energy rate components for the commercial class with the corresponding cost components. The Board considers the move towards cost recovery would result in appropriate demand and energy price signals for commercial customers. The Board also notes the minimum demand level of 5 kV.a provides for recovery of about 85% of customer costs and would be consistent with minimum demand levels of neighbouring utilities. The Board considers while cost recovery at the minimum demand level is an important consideration other considerations such as gradualism and comparability with neighbouring utilities would support the 5 kV.a minimum demand level proposed by Northland. Accordingly, the Board will approve the proposed increase in minimum billing demand for commercial customers to 5 kV.a from 2.4 kV.a and the reduction in demand charge to \$7.36 per kV.a from the current \$8.20 per kV.a. The Board directs Northland to reflect a minimum demand of 5 kV.a and a demand charge of \$7.36 per kV.a for the general service class, in the refiling of the Application.

4.3.3 Street Lights

Northland stated the street lighting rate schedule is being revised to cover nine different light types from the existing six. Northland proposed to transfer the rates for 50 W, 70 W and 100 W HPS lights from the space light rate class to the street light rate class because these lights are more indicative of a streetlight than a space light.

Northland stated the rationale for moving the lights to the street lights class is that they are not considered private lighting or space lights as they are paid for by the City of Yellowknife. (BR NUL YK 45 (b))

The Board accepts Northland's explanation for moving the space lights referred to above to the street lights class. Accordingly, the Board will approve the proposed transfer of the rates for 50 W, 70 W and 100 W HPS lights from the space light rate class to the street light rate class. The Board directs Northland to reflect this in the refiling of the Application.

4.3.4 Space Lights

Northland stated the space lighting rate schedule has been revised to cover six different light types from the existing nine. The rates for 50 W, 70 W and 100 W HPS lights have been transferred to the street light rate class.

The Board accepts the above change for the reasons stated under the street lights discussion.

4.3.5 Rider A

Northland proposed to use this Rider to recover the revenue shortfall between the proposed rates effective date, of January 1, 2005, to the rate implementation date decided by the Board. Northland also proposed to use Rider A to collect a Rider S outstanding balance of $11,577 and to refund the remaining Income Tax Rebate balance of $10,378. Rider S was established initially to flow through a purchased power cost adjustment from NWTPC and was set to zero by Northland, effective May 1, 1998 when the NWTPC adjustment was substantially collected leaving a small amount of $11,577 to be collected as part of these proceedings.

Northland set out details of the Rider A calculations in Schedule 12.3, as amended as of April 8, 2005. Rider A is a percent surcharge/refund applicable to customer bills.

The Board considers the proposed mechanism for refund/recovery of excess/shortfall amounts calculated by rate class, by way of a percent rider, and applicable to the base bill amounts, provides for equitable refund/recovery of excess/shortfall amounts by rate class. The Board also considers, including relatively small residual amounts of under or over collections applicable to Rider S and income tax rebates as part of Rider A is an administratively simple and practical way of disposing of these amounts. The Board will therefore approve the use of the Rider A mechanism for the refund/recovery of items referred to in this section and directs Northland to design Rider A in accordance with the foregoing comments, in its refiling of the Application.

4.3.6 Rider B Snare Cascades Hydro

The Snare Cascades Hydro Rider has been in effect since May 1, 2001 (Decision 3-2001) and was set at 0.5313 cents/kW.h to offset NWTPC's rider, of 0.5 cents/kW.h, that recovered the closing balance in the Snare Cascades Hydro Deferral Account amortized over 10 years, plus a cash return.

Northland forecast an over-collection of $14,672 by December 31, 2004 with respect to this Rider. Northland proposed to adjust Rider B to 0.5210 cents/kW.h to reflect the revised loss factor of 6.0% and to refund the over-collection.

The Board understands the Rider B mechanism provides for recovery of the amounts invoiced to Northland by NWTPC with respect to the Snare Cascades Hydro Rider and the amounts so invoiced are reconciled by comparing to amounts recovered from customers of Northland via Rider B. The amounts invoiced to Northland by NWTPC are on a per Kwh basis and the recovery via Rider B is also on a per Kwh basis, subject to adjustment for line loss. The Board considers the per Kwh mechanism for recovery of this portion of purchased power costs is consistent with the manner in which costs are incurred by Northland. The Board will therefore approve the use of the Rider B mechanism for recovery of amounts invoiced to Northland by NWTPC with respect to the Snare Cascades Hydro Rider and directs Northland to file a proposed Rider B adjusted for any change in the loss factors arising from this Decision, as part of its refiling of the Application.

4.3.7 Rider C

The NWTPC GRA Shortfall Adjustment Rider, Rider C, was intended to be a straight flow-through of Riders applied by NWTPC to purchased power costs.

The Board notes from Northland's GRA that Rider C will be rolled into base rates and Rider C set at zero percent. The Board also notes subsequent to filing of this GRA, the Board approved for Northland by way of Decision 9-2005, the recovery of NWTPC Riders S and P and refund of excess amounts collected to December 31, 2004 under Rider C, by way of Rider C.

The Board considers it appropriate to incorporate into Northland's base rates the current components of base rates charged to Northland by NWTPC for purchased power. The Board considers further that Riders such as NWTPC's Riders S and P should continue as part of Northland's Rider C since those Riders are not part of NWTPC's base rates. Further, any Rider C over collection amounts should continue to be refunded through Rider C. The Board directs Northland to design Rider C in accordance with these findings, and adjusted for any changes in loss factors arising from this Decision, in its refiling of the Application.

The Board notes the Rider C over collection as of December 31, 2004 was about $200,000. (Decision 9-2005; p.2) This is about 6.5% of the total amounts collected under Rider C in 2004. The Board is concerned that Northland's forecasting of Rider C revenues and corresponding costs has caused such a significant over collection of funds. In the future, the Board expects Northland to adjust Rider C on a timely basis as forecast loss factors change or if a consistent pattern of over/under collection is observed, so as to ensure there is no significant over or under collection in the Rider C account.

4.3.8 Rider P

Rider P, Power Purchase Adjustment Rider came into effect April 1, 1997 (Decision 8-97) as a result of NWTPC changing the demand and energy components of the purchased power rates. Rider P is part of the existing rates of Northland.

Northland proposed to roll Rider P into the base rates and set the rate to zero percent effective January 1, 2005.

The Board accepts Northland's proposal to roll Northland Rider P into base rates consistent with the Board's reasons set out above under the Rider C discussion.

4.4 TERMS AND CONDITIONS OF SERVICE

Northland submitted it has included for approval, as part of the Application, the revised Terms and Conditions of Service ("**T&Cs**"). The T&Cs apply directly to all customers within the service area of the Company. Northland stated the basic structure of the revised T&Cs has not changed significantly from the previous version, but enhancements to formatting and amendments to the text to reflect current business practices and procedures have been included to improve clarity.

The Board's Counsel examined the company on the proposed wording change to Article 3.1 concerning the process for amending the T&Cs. He noted that the proposed change shifts the onus to the Board to actually respond to any proposed amendments. (Tr., p.101)

Article 3.1 of the proposed T&Cs states in part as follows:

> "These terms and conditions have been approved by the Board. The Company may amend these terms and conditions by filing a notice of amendment with the Board. Included in the notice to the Board shall be notification of which Customer groups are affected by the amendment and an explanation of how affected Customers will be notified of the amendments. The amendment will take effect 60 days after such notice is filed, unless the Board otherwise directs." (Article 3.1 in part)

Northland submitted the wording of Article 3.1 is reasonable. Northland stated it would adopt a process under which it would circulate proposed changes to all interested parties, as well as the Board. (Tr., p.142)

The City opposed Northland's proposal where changes to the T&Cs could potentially take effect by default if the Board does not respond within the 60-day period. In this regard, the City stated:

> " However, the City does believe that the change ought to be approved by the Board. The City is somewhat uncomfortable with what Board counsel called the reverse onus or the onus on the Board which would be reflected in the amendment in Section 3.1." (Tr., p.162, *ll.*14-18)

The Board notes from Section 63(3) of the Public Utilities Act, that Board approval is required for amendments to T&Cs:

> "No terms and conditions of service or amendments to terms and conditions of service are of any effect until approved by the Board." (Section 63(3))

The Board interprets the above section to mean approval is required for amendments to the T&Cs. However, the Board considers the approval process could be simplified. The Board will accordingly direct Northland to amend Article 3.1 of the T&Cs to include the following words respecting approval process for amendments to T&Cs:

Article 3.1

These terms and conditions have been approved by the Board. The Company may amend these terms and conditions by filing a notice of amendment with the Board and interested parties from the preceding General Rate Application. Included in the notice shall be notification of which Customer groups are affected by the amendment and an explanation of how affected Customers will be notified of the amendments. The Board will either acknowledge the notice of the amendment to the Terms and Conditions or direct a further process to deal with the requested change as the Board deems appropriate. If the Board *acknowledges notice of the amendment, the amendment will take effect upon the date of such acknowledgement.*

No other issues were raised during the proceedings with respect to the proposed T&Cs. Accordingly, the Board directs Northland to refile the proposed T&Cs for approval, subject to incorporation of the change noted above with respect to Article 3.1, as part of its refiling of the Application.

5. REFILING OF THE APPLICATION

In the foregoing sections of this Decision, the Board made reference to a refiling of the application. The directions that are to be reflected in the refiling of the Application are listed below:

1. The Board directs Northland and the other parties to the Settlement to reassess the level of loss factors for 2005 and 2006 in light of the new information provided in response BR NUL YK 54 with respect to the 2004 actual loss factor and the impact of including this in the 5 year average for loss factors. Amendments to the Settlement, if any, resulting from these discussions should be included as part of the refiling of the Application. The Board will defer consideration of the Phase I Settlement and approval thereof until this reassessment has been completed. Likewise the Board will defer any directions respecting implementation of the Settlement until the reassessment is completed.

2. The Board directs Northland to file a proposal for initiating, administering and reporting on the delivery and success of the ARP including details of how the eligibility requirements for rebates noted by EN would be implemented, as part of the refiling of the Application.

3. The Board considers the Northland proposal for rate treatment of the cost of the ARP to be reasonable and accordingly, directs the company to file a proposed rate rider with respect to the ARP as part of the refiling of the Application.

4. The Board directs Northland to design the ARP rider to be applicable to all customers of Northland, in its refiling of the Application.

5. The Board directs Northland to change the classification of the demand component of purchased power costs to a demand classification in its refiling of the Application.

6. The Board directs Northland to classify A&G expense on the basis of all service costs excluding purchased power costs, A&G expense and PLPD, in its refiling of the Application.

7. The Board directs Northland to remove the 2% energy weighting of meter assets in its refiling of the Application.

8. In the interest of mitigating rate impacts, the Board will accept a revenue to cost ratio of 95% for the residential class. The Board directs Northland to design rates in accordance with these findings, subject to the constraint the increase/decrease for any one rate class is less than 10%, in its refiling of the Application.

9. The Board accepts the increase in the residential fixed charge from the existing $15 per month to $18 per month as proposed by Northland. The Board directs Northland to reflect a residential fixed charge of $18 per month in the refiling of the Application.

10. The Board directs Northland to reflect a minimum demand of 5 kV.a and a demand charge of $7.36 per kV.a for the general service class, in the refiling of the application.

11. The Board will approve the proposed transfer of the rates for 50 W, 70 W and 100 W HPS lights from the space light rate class to the street light rate class. The Board directs Northland to reflect this in the refiling of the Application.

12. The Board approves the use of the Rider A mechanism for the refund/recovery of items referred to in section 4.3.5 and directs Northland to design Rider A in accordance with the comments in section 4.3.5, in its refiling of the Application.

13. The Board approves the use of the Rider B mechanism for recovery of amounts invoiced to Northland by NWTPC with respect to the Snare Cascades Hydro Rider and directs Northland to file a proposed Rider B adjusted for any change in the loss factors arising from this Decision, as part of its refiling of the Application.

14. The Board considers that Riders such as NWTPC's Riders S and P should continue as part of Northland's Rider C since those Riders are not part of NWTPC's base rates. Further, any Rider C over collection amounts should continue to be refunded through Rider C. The Board directs Northland to design Rider C in accordance with these findings, adjusted for any changes in loss factors arising from this Decision, in its refiling of the Application.

15. The Board directs Northland to refile the proposed T&Cs for approval, subject to incorporation of the change noted above with respect to Article 3.1, as part of its refiling of the Application.

16. The Board directs Northland to refile the 2005/2006 GRA Application with the Board and interested parties within 30 days of the Decision. Interested parties will have an opportunity to comment on the refiling of the Application within 14 days of the refiling and the Board will render its final Decision thereafter.

6. SUMMARY OF DIRECTIONS FOR THE NEXT GRA

The following is a listing of directions to Northland for the next GRA:

1. The Board expressed concern that the method of determining the annual loss factor, the level of which is driven largely by the amount of unbilled revenues at year end, may be causing fluctuations in the loss percent from year to year with consequent impact on earnings. The Board also expressed concern that the absence of a transparent method for determining line losses for a given year with reasonable accuracy is a concern for future line loss determination. In order to address these concerns, Northland is directed to develop procedures for determining actual line loss factors for each year, which are reasonably reflective of the electrical line losses for that year. To the extent the unbilled consumption is a factor amongst others causing fluctuations in overall loss factors from year to year, the percent loss factor applicable to electrical losses should be identified separately from the loss factor applicable to other factors under the category of unaccounted for losses. Northland should institute the above procedures with immediate effect and explain how these procedures address the accurate determination of forecast loss factors, at the next GRA.

2. Northland is also directed to provide a comparison of forecast electrical loss factors with those that were anticipated at the time of the 25 kV conversion application, with explanations for differences, at the time of the next GRA.

3. The Board directs Northland to investigate the benefits and market potential for time of use rates and address this matter at the time of the next GRA.

4. During the hearing, Northland indicated that its parent, ATCO Electric Limited had instituted a pilot program for smart meters in the communities of Grande Prairie and Drumheller, Alberta. The Board directs Northland to report on the lessons learned from this pilot program and address the applicability of these lessons in the Northland service area, at the time of the next GRA.

5. Northland indicated it is prepared to track customer contributions by rate class in the future and to assess the ability to look at historical contributions by rate class. Accordingly, the Board directs Northland to begin tracking future contributions by rate class, commencing with the beginning of the 2005 test year. Northland is also directed to assess the tracking of historical contributions having regard to the costs and the benefits and to reflect or report on the outcome at the time of the next GRA.

6. The Board directs Northland to review all classification factors to determine if they remain appropriate and to reflect the results in the next Phase II application. The scope of the study should bear in mind the costs involved in conducting the study and the benefits in terms of enhancing the accuracy of cost classification and allocation by rate class.

7. BOARD ORDER

NOW THEREFORE, IT IS ORDERED THAT:

1. Northland Utilities (Yellowknife) Limited shall refile its 2005/2006 GRA within 30 days of this Decision in accordance with the determinations and directions contained in this Decision.

2. Nothing in this Decision and order shall bind, affect or prejudice the Board in its Consideration of any other matter or question relating to Northland Utilities (Yellowknife) Limited.

ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES

DATED August 18, 2005
John E. Hill
Chairman

FOLLOWING IS

APPENDIX A

ATTACHED TO AND FORMING PART OF

THE PUBLIC UTILITIES BOARD

OF THE NORTHWEST TERRITORIES

DECISION 12-2005

DATED August 18, 2005

IN THE MATTER of the General Rate Application filed by Northland Utilities (Yellowknife) Limited with respect to the years 2005 and 2006;

AND IN THE MATTER of a Negotiated Settlement reached between Northland Utilities (Yellowknife) Limited and Interveners to the referenced proceedings;

AND IN THE MATTER of an Application by Northland Utilities (Yellowknife) Limited seeking NWTPUB approval of the Negotiated Settlement.

NORTHLAND UTILITIES (YELLOWKNIFE) LIMITED
2005/2006 GENERAL RATE APPLICATION
NEGOTIATED SETTLEMENT

1. Northland Utilities (Yellowknife) Limited ("NUL") has been successful in reaching a Negotiated Settlement with the Intervenors, who are signatories to the attached agreement, regarding all Phase I issues raised by NUL's General Rate Application ("GRA") filing.

2. The participants to the NUL Negotiated Settlement were as follows:

   - City of Yellowknife
   - Northwest Territories Power Corporation

3. This Negotiated Settlement is presented to the Northwest Territories Public Utilities Board as a "package deal" as more fully described in the attached Negotiated Settlement Agreement, paragraph 3.

4. NUL requests that the Board approve the 2005 Revenue Requirement, and the 2006 Revenue Requirement, as summarized in Appendix 1, attached to the Negotiated Settlement Agreement.

5. It is expressly agreed that the execution of the attached Negotiated Settlement Agreement by Intervenors signifies their support for the granting of this Application and further confirms that such parties consider this Negotiated Settlement, as filed, to yield just and reasonable rates and to be in the public interest.

ALL OF WHICH IS RESPECTFULLY SUBMITTED this 24th day of March, 2005.

D.A. De Champlain

Northland Utilities (Yellowknife) Limited

NORTHLAND UTILITIES (YELLOWKNIFE) LIMITED
2005/2006 GENERAL RATE APPLICATION
NEGOTIATED SETTLEMENT

A. INTRODUCTION

In consideration of the mutual covenants set out in this settlement agreement (the "Negotiated Settlement"), the parties hereto agree as follows:

1. Northland Utilities (Yellowknife) Limited ("NUL") has concluded this Negotiated Settlement with the parties hereto for the years 2005 and 2006 covering the functions performed by NUL. All of the Phase I issues raised by NUL's General Rate Application ("GRA") are disposed of in accordance with the terms hereof.

2. It is understood and agreed that:

   (a) all settlement offers were exchanged and discussed among the parties on a confidential and without prejudice basis; and

   (b) additional information provided by NUL in respect of and relating to NUL's 2005 and 2006 General Rate Application as filed with the Board (the "Application"), was not provided on a confidential or without prejudice basis.

3. The terms of the Negotiated Settlement reflect a "package deal" and, therefore, it is not possible for the Northwest Territories Public Utilities Board ("NWTPUB" or "Board") to accept any part(s) of the Negotiated Settlement and still reflect the overall agreement reached as between the parties.

The parties specifically agree that it is not possible for the Board to impose any terms and conditions on any approval of this Negotiated Settlement and still preserve the agreed upon "package deal" agreement, as this Negotiated Settlement addresses all Phase I GRA matters. Thus, if the Board does not accept the complete Negotiated Settlement, as filed, there shall be no settlement among the parties of the issues raised by the NUL Application and the parties hereto will be free to litigate all or any such issues before the Board. Notwithstanding the above, should the Board decide to approve an addition to the negotiated revenue requirement, as derived pursuant to this agreement to facilitate an appliance rebate program similar to that advanced by Ecology North in these proceedings, the negotiated revenue requirement shall be automatically adjusted to include such an amount for 2005 and 2006 as is approved by the Board.

4. Appended hereto are executed signature pages from interested parties (acceptable in counterparts) which indicate their concurrence with the Negotiated Settlement as reflected in this agreement. It is agreed that NUL will request that the Board approve the Negotiated Settlement and that parties to this Negotiated Settlement will support NUL's request.

5. Immediately after the Negotiated Settlement is executed by all of the signatories hereto, NUL will request that the Board approve the Negotiated Settlement, including the 2005 Revenue Requirement, effective January 1, 2005; and the 2006 Revenue Requirement, effective January 1, 2006, both as summarized in Appendix 1 attached hereto.

6. NUL's 2005 Revenue Requirement shall be $27,827,000.

7. NUL's 2006 Revenue Requirement shall be $28,520,000.

8. The parties hereto agree that the following specific changes including, associated impacts, shall be made to NUL's 2005/2006 Phase I Application, as same was filed with the Board, as updated during the negotiated settlement discussions, as well as, to reflect errors and corrections to the original filing.

		($000's)	
		2005	**2006**
i.	Purchase Power Expense	22	(158)
ii.	Operating Expenses	(29)	(55)
ii.	Taxes other than income*	(11)	(16)
iv.	Depreciation		
	- Reserve Adjustments – Accounts 483.20 and 484.10	(10.8)	(10.8)
	- Accounts 477.10 and 479.10	(362)	(338)
v.	Return on Rate Base		
	- ROE @ 10.00%	(91)	(103)
	- Customer Deposits included in capital structure	(6)	(6)
	- Lead Lag	-	(1)
	- Cost of New Debt	(5)	(16)
	- Capital Expenditures **	(9)	-
vi.	Income Taxes		
	- Revised CCA Rates ***	(44)	(109)
	Reductions to filed revenue requirement	(545.8)	(812.8)
vii.	Revenue Forecast	(25)	126
	Reductions to filed rate increase	(570.8)	(686.8)

* Taxes other than income have been adjusted for the impact of the negotiated settlement on franchise fees.

** The study costs of $140,000 relating to 25kV conversion project will remain in work in progress attracting AFUDC through 2004 and 2005 and will be capitalized as part of the 25 kV conversion addition in 2005.

*** It is expressly agreed and understood that, at this time, the reduced CCA rates, as proposed in the February 23, 2005 Federal Budget, have not been enacted. This reduction is subject to such reduced rates being officially enacted. Should this not occur, the negotiated settlement will be automatically amended to increase the approved revenue requirement by the amount of the reduction to CCA rates identified herein.

9. NUL undertakes to file updates to all GRA schedules related to Phase I and Phase II of these proceedings to reflect the impacts of this negotiated settlement.

10. All costs relating to NUL's revenue requirement for 2005 and 2006, which result from amendments to the *Public Utilities Act* or other legislative changes, including changes to relevant regulations and changes in general policies as published by the relevant authorities, which occur from the date hereof that have not otherwise been expressly contemplated in this Negotiated Settlement shall be flowed through (dollar for dollar) to NUL's Revenue Requirement.

11. The Application shall be deemed to be amended to the extent necessary to reflect the provisions of this Negotiated Settlement. The mechanisms described in the Application with respect to deferral accounts shall be implemented as described therein.

12. NUL will maintain quality of service and ensure that cost savings are not obtained at the expense of system reliability, safety and/or customer satisfaction. NUL will continue to use good utility operating practices.

13. NUL agrees to pay Intervenor costs associated with the GRA proceedings and this Negotiated Settlement upon receipt of an invoice from each Intervenor. Each Intervenor agrees to provide an invoice of such costs, not later than 30 days after the Board issues an Order approving NUL Revenue Requirements on a final basis for 2005 and 2006, and to provide in writing that its costs have been reasonably incurred and that its cost claim has been prepared in accordance with the Board's guidelines for intervenor cost claims.

    NUL will advance a summary of costs paid by NUL to all Interveners to the Board within 60 days of receiving the Board's Order. The summary will also include out of pocket costs reasonably incurred by NUL in respect of its participation in the GRA proceeding and this Negotiated Settlement. NUL will ask the Board to approve the recovery of these costs from NUL's Hearing Cost Reserve Account. Each Intervenor will be responsible for providing any additional information the Board may request in respect to its cost claim. In the event that the Board finds that any portion of costs paid by NUL in respect of any Intervenor may not be recovered by NUL from NUL's Hearing Cost Reserve Account, that Intervenor shall pay the disallowed amount to NUL within 30 days of the Board advising NUL of its decision to not approve the recovery of such costs.

14. The final Revenue Requirement established for NUL for 2005, in accordance with this Negotiated Settlement, will be implemented effective on January 1, 2005. The final Revenue Requirement established for NUL for 2006 in accordance with the Negotiated Settlement will be implemented on January 1, 2006.

15. All parties to this Negotiated Settlement agree that the 2005 and 2006 Revenue Requirements, as proposed herein, are fair, reasonable and in the public interest.

16. The parties hereto agree that all matters relating to NUL's Terms and Conditions of Service will be addressed in Phase II of these proceedings. Any changes to such Term and Conditions resulting from the Phase II proceeding will not impact this negotiated settlement.

17. This Negotiated Settlement does not preclude or prejudice the rights of parties to pursue any issues of concern to them in any proceedings in respect of 2007 or subsequent years.

18. If NUL claims and the CRA has accepted any income tax deductions for 2005 or 2006 arising from the expensing of costs that have been capitalized for regulatory purposes, NUL agrees to flow through to customers the benefits of any such deductions. If these deductions are reversed as a result of any subsequent action or audit by the CRA, the benefits previously flowed through to customers will be reversed and the full amount thereof, plus any associated interest and penalties charged by CRA, will be collected from customers.

SUBMITTED THIS 24th DAY OF March, 2005 by Northland Utilities (Yellowknife) Limited.

W.A.D. Champlain

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NORTHLAND UTILITIES (YELLOWKNIFE) LIMITED
2005/2006 GENERAL RATE APPLICATION
NEGOTIATED SETTLEMENT

ACCEPTED AND AGREED TO:
(May be executed in counterpart)

City of Yellowknife	**Northwest Territories Power Corporation**
Signature:	Signature:
Name (Print): Thomas Marriott	Name (Print):
Title: solicitor/authorized signatory	Title:
Date: March 31, 2005	Date:

NORTHLAND UTILITIES (YELLOWKNIFE) LIMITED
2005/2006 GENERAL RATE APPLICATION
NEGOTIATED SETTLEMENT

ACCEPTED AND AGREED TO:
(May be executed in counterpart)

City of Yellowknife	**Northwest Territories Power Corporation**
Signature:	Signature: Judith Boucher
Name (Print):	Name (Print): JUDITH BOUCHER
Title:	Title: DIRECTOR, FINANCE & CFO
Date:	Date: Mar. 24/05

Appendix 1

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Utility Revenue Requirement
($000s)

Line No.	Description	per Application Forecast 2005	per Application Forecast 2006	Negotiated Settlement Forecast 2005	Negotiated Settlement Forecast 2006	Variance	
1	**Revenues**						
2	Retail revenues	28,081	29,035	27,535	28,222	(546)	(813)
3	Other revenue	292	298	292	298	0	0
4	**Total Revenues**	28,373	29,333	27,827	28,520	(546)	(813)
5							
6	**Costs**						
7	Purchase power	22,163	22,572	22,185	22,414	22	(158)
8	Operations and maintenance	2,106	2,168	2,077	2,113	(29)	(55)
9	Taxes other than income	736	756	725	740	(11)	(16)
10	Amortization of deferred costs/credits	(54)	(54)	(54)	(54)	-	-
11	Depreciation	1,356	1,509	1,104	1,259	(252)	(250)
12	Amortization of contributions	(69)	(79)	(69)	(79)	-	-
13	Return on rate base	1,599	1,783	1,532	1,723	(67)	(60)
14	Income taxes	536	678	327	404	(209)	(274)
15	**Total Costs**	28,373	29,333	27,827	28,520	(546)	(813)
					Changes to revenues at existing rates	(25)	126
					Reduction in filed Rate Increase	(571)	(687)
					Rate Increase Filed	542	962
					Negotiated Settlement Rate (Decrease) / Increase	(29)	275

FOLLOWING IS

APPENDIX B

ATTACHED TO AND FORMING PART OF

THE PUBLIC UTILITIES BOARD

OF THE NORTHWEST TERRITORIES

DECISION 12-2005

DATED August 18, 2005

NORTHLAND UTILITIES
(YELLOWKNIFE) LIMITED
An ATCO Company

April 8, 2005

Northwest Territories
Public Utilities Board
203 – 62 Woodland Drive
Box 4211
Hay River, NT X0E 1G1

Attention: Mr. John Hill, Chairman

Dear Sir:

Re: Northland Utilities (Yellowknife) Limited
2005/2006 General Rate Application

Further to the Board's letter of March 14, 2005, NUL is refiling the affected portions of its application reflecting the Negotiated Settlement filed with the Board March 31, 2005. The revised rates also reflect the correction to the Franchise Tax allocation identified in information request YK-NUL-YK-25.

Enclosed are the following:

- Revised Phase I Schedules
- Revised Section 11 Phase II Cost of Service Schedules and Models
- Revised Section 12 Phase II Rate Design Schedules
- Revised Section 13 Phase II Rate Schedules

If you have any questions please call me at (780) 420-5420.

Yours truly,

NORTHLAND UTILITIES (YELLOWKNIFE) LIMITED

Original Signed by:

David Freedman
Manager, Regulation and Business Plans

Encl.

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Index of Revised Phase I Schedules

Schedule 1.1

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Utility Revenue Requirement
($000s)

Line No.	Description	Cross Ref.	per Application Forecast 2005	per Application Forecast 2006	Negotiated Settlement Forecast 2005	Negotiated Settlement Forecast 2006	Variance	
1	**Revenues**							
2	Retail revenues	S.2.1 L.28	28,081	29,035	27,535	28,222	(546)	(813)
3	Other revenue		292	298	292	298	-	-
4	**Total Revenues**		28,373	29,333	27,827	28,520	(546)	(813)
5								
6	**Costs**							
7	Purchase power	S.3 L.19	22,163	22,572	22,185	22,414	22	(158)
8	Operations and maintenance	S.4.1 L. 41	2,106	2,168	2,077	2,113	(29)	(55)
9	Taxes other than income		736	756	725	740	(11)	(16)
10	Amortization of deferred costs/credits		(54)	(54)	(54)	(54)	-	-
11	Depreciation	S.6 L.38	1,356	1,509	1,104	1,259	(252)	(250)
12	Amortization of contributions		(69)	(79)	(69)	(79)	-	-
13	Return on rate base	S.7.1 L.5,11,16,22	1,599	1,783	1,532	1,723	(67)	(60)
14	Income taxes	S.9 L.24	536	678	327	404	(209)	(274)
15	**Total Costs**		28,373	29,333	27,827	28,520	(546)	(813)

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Summary of Customers, Energy Sales and Revenue

Schedule 2.1

			per Application				Negotiated Settlement			
			Forecast		Forecast		Forecast		Forecast	
Line No.	Description	Cross Ref.	2005 Existing	2005 Proposed	2006 Existing	2006 Proposed	2005 Existing	2005 Proposed	2006 Existing	2006 Proposed
1	**Residential**									
2	Customers		6,471	6,471	6,580	6,580	6,471	6,471	6,580	6,580
3	Sales in MWh		58,204	58,204	59,168	59,168	58,362	58,362	59,328	59,328
4	MWh sales per customer		9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
5	Revenue ($000s)		10,263	10,634	10,434	10,966	10,288	10,292	10,460	10,580
6	Cents per KWh		17.63	18.27	17.63	18.53	17.63	17.63	17.63	17.83
7	**Commercial**									
8	Customers		1,057	1,057	1,071	1,071	1,050	1,050	1,056	1,056
9	Sales in MWh		103,173	103,173	105,357	105,357	103,173	103,173	104,193	104,193
10	MWh sales per customer		97.6	97.6	98.4	98.4	98.3	98.3	98.7	98.7
11	Revenue ($000s)		16,581	16,719	16,937	17,323	16,581	16,615	16,784	17,001
12	Cents per KWh		16.07	16.20	16.08	16.44	16.07	16.10	16.11	16.32
13	**Street lights**									
14	Sales in MWh		1,540	1,540	1,553	1,553	1,540	1,540	1,553	1,553
15	Revenue ($000s)		679	713	686	730	679	613	687	626
16	Cents per KWh		44.09	46.30	44.17	47.00	44.09	39.80	44.17	40.31
17	**Space lights**									
18	Sales in MWh		74	74	74	74	74	74	74	74
19	Revenue ($000s)		16	15	16	16	16	15	16	15
20	Cents per KWh		21.62	20.27	21.62	21.62	21.62	20.27	21.62	20.27
21	**Total Company**									
22	Customers		7,528	7,528	7,651	7,651	7,521	7,521	7,636	7,636
23	Sales in MWh		162,991	162,991	166,152	166,152	163,149	163,149	165,148	165,148
24	Revenue ($000s)		27,539	28,081	28,073	29,035	27,564	27,535	27,947	28,222
25	Cents/KWh		16.90	17.23	16.90	17.47	16.89	16.88	16.92	17.09
28	Retail Revenues	S.1 L.2	27,539	28,081	28,073	29,035	27,564	27,535	27,947	28,222
29	Rate Increase from Existing Rates			542		962		(29)		275
30	Rate Increase %			2.0%		3.4%		-0.1%		1.0%

Schedule 3

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Schedule of Energy Losses, Peak and Load Factor
($000s)

Line No.	Description	Cross Ref.	per Application Forecast 2005	per Application Forecast 2006	Negotiated Settlement Forecast 2005	Negotiated Settlement Forecast 2006
1	**Sales and Losses**					
2	Total energy sales - MWh	S.2.1 L.23	162,991	166,152	163,149	165,148
3	Losses - MWh		9,781	9,803	9,789	9,579
4	Losses -%		6.00%	5.90%	6.00%	5.80%
5	Total Purchases MWh		172,772	175,955	172,938	174,727
6	**Peak - MW**					
7	Total Peak		31.61	32.19	31.64	31.96
8	Adjustment for 85% ratchet on demand (note 1)		-	-	-	-
9	Billed Peak		31.61	32.19	31.64	31.96
11	**Purchase Power Rates**					
12	Energy Charge		0.1055	0.1055	0.1055	0.1055
13	Snare Cascade Rider		0.0050	0.0050	0.0050	0.0050
14	Demand Charge		8.10	8.10	8.10	8.10
15	**Purchase Power Expense**					
16	Energy Expense		18,227	18,563	18,245	18,433
17	Snare Cascade Rider		864	880	865	874
18	Demand Charge		3,072	3,129	3,075	3,107
19	Total Purchase Power Expense	S.1 L.7	22,163	22,572	22,185	22,414

Note 1 - Effective November 1, 2003 NTCP Demand Charge changed from and 85% ratchet on demand to a 100% ratchet on demand.

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Operations and Maintenance Expenses
($000s)

Schedule 4.1

Line No.	Description	Cross Ref.	per Application Forecast 2005	per Application Forecast 2006	Negotiated Settlement Forecast 2005	Negotiated Settlement Forecast 2006
1	**Distribution**					
2	87000 - Supervision		93	96	93	96
3	87200 - Vehicle Depreciation		(28)	(29)	(28)	(29)
4	87300 - Maintenance	S.4.2 L.2	391	387	391	387
5	87500 - Meter and Meter Testing	S.4.2 L.9	21	22	21	22
6	87700 - Transformer Repair and Replacement		2	2	2	2
7	87800 - Street Light Maintenance	S.4.2 L 13	40	42	40	42
8			519	520	519	520
9	**General**					
10	88400 - Communication		7	7	7	7
11	88800 - Carrying Costs Company Owned Houses		5	5	5	5
12	88900 - Maintenance Warehouse and Office	S.4.2 L 18	78	69	78	69
13	89100 - Material Management		5	6	5	6
14			95	87	95	87
15	**Public information**					
16	70100 - Public Information Administration		58	57	58	57
17	70200 - General Public Information	S.4.2 L 22	54	55	54	55
18			112	112	112	112
19	**Customer accounting**					
20	71000 - Supervision		61	63	61	63
21	71100 - Customer Applications and Service Orders	S.4.2 L 26	88	91	88	91
22	71200 - Meter Reading		73	76	73	76
23	71300 - Customer Billing and Accounting	S.4.2 L 29	238	250	238	250
24	71400 - Revenue Collections	S.4.2 L 33	129	133	129	133
25	71500 - Collection of Deliquent Accounts		50	52	50	52
26	71800 - Uncollectible Accounts	S.4.2 L .37	16	16	16	16
27			655	681	655	681
28	**Administration and general**					
29	72100 - Administrative Expenses	S.4.2 L 40	348	369	348	369
30	72200 - Head Office Fees	S.4.2 L 46	194	200	194	200
31	72300 - Insurance		41	44	41	44
32	72500 - Employee Expenses		59	66	59	66
33	72600 - Safety and Training	S.4.2 L 50	90	96	90	96
34			732	775	732	775
35						
36	Negotiated reduction in operations and maintenance expenses		-	-	(29)	(55)
37						
38	Less:					
39	Donations		(7)	(7)	(7)	(7)
40						
41	Total operations and maintenance expenses	S.1 L.8	2,106	2,168	2,077	2,113

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Calculation of Depreciation Expense 2005

Schedule 6.3

Line No.	Acct.	Description	Cross Ref.	2005 YFR/ Curve	Life	Net Salvage	Depn. Rates	2005 31-Dec-04 Investment	Depreciation Expense	Amortization of Differences	Negotiated Settlement Total Depreciaton Expense	per Application Total Depreciaton Expense	Variance
1		Distribution Plant											
2	471 00	Land Rights		R3	75	0%	1.51%	173,627	2,622	(96)	2,526	2,526	-
3	473 00	Poles, Towers & Fixtures		R4	45	-35%	3.13%	7,727,471	242,349	(20,964)	221,385	223,385	(2,000)
4	474 00	Overhead Conductor		R4	40	-30%	3.41%	3,937,584	136,973	(3,240)	133,733	133,733	-
5	474 10	Services - Overhead		R3	40	-10%	3.00%	843,566	25,307	-	25,307	25,307	-
6	475 00	Underground Conductor		R3	50	0%	2.29%	4,551,266	104,224	972	105,196	105,196	-
7	475 10	Services - Underground		R3	40	0%	2.48%	159,121	3,946	(468)	3,478	3,478	-
8	476 10	Meters		L0.5	20	1%	5.41%	459,783	24,428	15,960	40,388	40,388	-
9	477 10	Substation Equipment - existing			8		8.41%	3,094,739	138,867	-	138,867	260,268	(121,401)
10	477 10	Substation Equipment - post 2004		R3	31	-10%	3.34%	-	13,560	-	13,560	13,560	-
11	478 10	Street Lighting		S2.5	35	-5%	3.22%	2,979,095	96,488	(5,208)	91,280	91,280	-
12	479 10	Line Transformers - existing			8		9.76%	2,670,212	139,000	-	139,000	260,613	(121,613)
13	479 10	Line Transformers - post 1999		S2.5	35	-30%	4.09%	1,122,042	47,682	2,976	50,658	50,658	-
14		Total Distribution Plant						27,718,506	975,446	(10,068)	965,378	1,210,392	(245,014)
15													
16		General Plant											
17	482 00	Structures & Improvements		S2	38	5%	2.76%	1,551,382	42,883	(192)	42,691	42,691	-
18	483 00	Office Furniture & Equipment		S4	15	2%	6.63%	64,439	4,239	240	4,479	4,479	-
19	483 20	Computer Hardware		R4	5	0%	19.99%	27,559	5,676	780	6,456	7,620	(1,164)
20	484 10	Transportation Equipment		L2	7	25%	8.97%	1,144,867	50,387	6,847	57,234	66,815	(9,581)
21	484 50	Heavy Work Equipment		R3	26	15%	3.51%	-	-	-	-	-	-
22	485 00	Tool & Work Equipment		S3	10	0%	10.08%	262,329	26,072	60	26,132	26,132	-
23	486 00	Communication Equipment		R4	15	2%	6.37%	139,326	8,902	1,536	10,438	10,438	-
24	488 20	Company Housing					1.08%	175,815	1,899	-	1,899	1,899	-
25	496 01	Collection Management			5		20.00%	-	2,000	-	2,000	2,000	-
26	496 02	Oracle Budgeting			10		10.00%	-	900	-	900	900	-
27	496 76	Oracle Financials			10		10.00%	120,000	12,000	-	12,000	12,000	-
28		Total General Plant						3,485,717	154,958	9,271	164,229	174,974	(10,745)
29													
30		Plant Studied						31,204,223	1,130,404	(797)	1,129,607	1,385,366	(255,759)
31		Plant Not Studied						306,911	-				
32		Total Plant						31,511,134	1,130,404				
33													
34	4x0 00	Land						306,911					
35								306,911	-				
36	Less:	Depreciation Capitalized									25,520	29,265	(3,745)
37													
38		Depreciation Expense	S.1 L.11								1,104,087	1,356,101	(252,014)
39													

Note: Depreciation expense for an account for a month is calculated by multipling 1/12 of the annual account depreciation rate by the previous month end account plant in service. Multiplying the annual depreciation rate by the opening plant in service provides an approximation of the annual depreciation expense. The actual depreciation expense includes the impact of the amount and timing of additions and retirements.

Forecast depreciation for Transportation Equipment and Heavy Work Equipment (Accounts 484 10 and 484 50) is developed using a composite rate applied to the forecast balance of the two accounts in total.

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Calculation of Depreciation Expense 2006

Schedule 6.4

Line No.	Acct.	Description	Cross Ref.	2006 YFR/ Curve	Life	Net Salvage	Depn. Rates	2006 31-Dec-05 Investment	Depreciation Expense	Amortization of Differences	Negotiated Settlement Total Depreciaton Expense	per Application Total Depreciaton Expense	Variance
1		Distribution Plant											
2	471 00	Land Rights		R3	75	0%	1.51%	173,627	2,622	(96)	2,526	2,526	-
3	473 00	Poles, Towers & Fixtures		R4	45	-35%	3.13%	8,362,915	264,121	(20,964)	243,157	243,157	-
4	474 00	Overhead Conductor		R4	40	-30%	3.41%	4,298,881	149,165	(3,240)	145,925	145,925	-
5	474 10	Services - Overhead		R3	40	-10%	3.00%	843,566	25,307	-	25,307	25,307	-
6	475 00	Underground Conductor		R3	50	0%	2.29%	4,645,211	106,375	972	107,347	107,347	-
7	475 10	Services - Underground		R3	40	0%	2.48%	159,121	3,946	(468)	3,478	3,478	-
8	476 10	Meters		L0.5	20	1%	5.41%	456,783	24,267	15,960	40,227	40,227	-
9	477 10	Substation Equipment - existing			8		8.41%	3,094,739	138,867	-	138,867	260,268	(121,401)
10	477 10	Substation Equipment - post 2004		R3	31	-10%	3.34%	1,644,000	54,910	-	54,910	54,910	-
11	478 10	Street Lighting		S2.5	35	-5%	3.22%	3,181,195	102,921	(5,208)	97,713	97,713	-
12	479 10	Line Transformers - existing			8		10.96%	2,290,819	129,464	-	129,464	251,074	(121,610)
13	479 10	Line Transformers - post 1999		S2.5	35	-30%	4.09%	2,861,595	118,753	2,976	121,729	121,729	-
14		Total Distribution Plant						32,012,452	1,120,718	(10,068)	1,110,650	1,353,661	(243,011)
15													
16		General Plant											
17	482 00	Structures & Improvements		S2	38	5%	2.76%	1,577,367	43,570	(192)	43,378	43,378	-
18	483 00	Office Furniture & Equipment		S4	15	2%	6.63%	64,839	4,265	240	4,505	4,505	-
19	483 20	Computer Hardware		R4	5	0%	19.90%	37,559	7,591	780	8,371	9,535	(1,164)
20	484 10	Transportation Equipment		L2	7	25%	8.97%	1,160,491	51,659	6,847	58,506	68,087	(9,581)
21	484 50	Heavy Work Equipment		R3	26	15%	3.51%	-	-	-	-	-	-
22	485 00	Tool & Work Equipment		S3	10	0%	10.08%	293,829	29,069	60	29,129	29,129	-
23	486 00	Communication Equipment		R4	15	2%	6.37%	144,326	9,204	1,536	10,740	10,740	-
24	488 20	Company Housing					1.08%	175,815	1,899	-	1,899	1,899	-
25	496 01	Collection Management			5	0%	20.00%	20,000	4,000	-	4,000	4,000	-
26	496 02	Oracle Budgeting			10	0%	10.00%	18,000	1,800	-	1,800	1,800	-
27	496 76	Oracle Financials			10	0%	10.00%	120,000	12,000	-	12,000	12,000	-
28		Total General Plant						3,612,226	165,057	9,271	174,328	185,073	(10,745)
29													
30		Plant Studied						35,624,678	1,285,775	(797)	1,284,978	1,538,734	(253,756)
31		Plant Not Studied						306,911	-				
32		Total Plant						35,931,589	1,285,775				
33													
34	4x0 00	Land						306,911	-				
35								306,911	-				
36	Less:	Depreciation Capitalized									26,077	29,822	(3,745)
37													
38		Depreciation Expense	S.1 L.11								1,258,901	1,508,912	(250,011)
39													

Note: Depreciation expense for an account for a month is calculated by multipling 1/12 of the annual account depreciation rate by the previous month end account plant in service. Multiplying the annual depreciation rate by the opening plant in service provides an approximation of the annual depreciation expense. The actual depreciation expense includes the impact of the amount and timing of additions and retirements.

Forecast depreciation for Transportation Equipment and Heavy Work Equipment (Accounts 484 10 and 484 50) is developed using a composite rate applied to the forecast balance of the two accounts in total.

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Return on Rate Base
($000s)

Schedule 7.1

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
1	**2005 Forecast per Application**						
2	Long-term debt	S.7.3 L.15	11,300	59.43%	12,005	6.17%	740
3	Common stock		7,523	39.57%	7,993	10.75%	859
4	No Cost Capital		191	1.00%	203	0.00%	0
5	Total	S.7.5 L.21	19,014	100%	20,200	7.92%	1,599
6	**2005 Forecast per Negotiated Settlement**						
7	Long-term debt	S.7.3 L.31	11,222	58.46%	11,857	6.12%	726
8	Common stock		7,602	39.60%	8,032	10.00%	803
9	Consumer Deposits		182	0.95%	192	1.77%	3
10	No Cost Capital		191	0.99%	202	0.00%	0
11	Total	S.7.5 L.21 S.1 L.13	19,196	100%	20,284	7.55%	1,532
12	**2006 Forecast per Application**						
13	Long-term debt	S.7.3 L.15	12,600	59.33%	13,288	6.24%	829
14	Common stock		8,411	39.61%	8,871	10.75%	954
15	No Cost Capital		226	1.06%	238	0.00%	0
16	Total	S.7.5 L.21	21,237	100%	22,397	7.96%	1,783
17	**2006 Forecast per Negotiated Settlement**						
18	Long-term debt	S.7.3 L.31	12,531	58.47%	13,316	6.14%	818
19	Common stock		8,481	39.57%	9,012	10.00%	901
20	Consumer Deposits		193	0.90%	205	1.77%	4
21	No Cost Capital		226	1.05%	240	0.00%	0
22	Total	S.7.5 L.21 S.1 L.13	21,431	100%	22,774	7.57%	1,723

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Schedule of Debt Capital Employed and Embedded Cost
($000's)

Line No.												
1	**2005 Forecast per Application**						Net Capital Employed					
2						Principal		Per $100 of		Principal		Average
3			Issue	Coupon	Maturity	Amount	Total	Principal	Effective	Outstanding	Carrying	Embedded
4	Description	Series	Date	Rate	Date	Offered	Amount	Amount	Cost Rate *	31-Dec-03	Cost	Cost Rate
5	LT Adv. - Parent	I	11/6/2001	4.84%	2006	500	500	100.00	4.95%	500	25	
6		H	12/1/2000	6.97%	2008	500	500	100.00	7.05%	500	35	
7		J	11/26/2002	6.15%	2017	7,100	7,100	100.00	6.21%	7,100	441	
8		G	8/12/1999	6.80%	2019	500	500	100.00	6.85%	500	34	
9		K	1/23/2004	5.43%	2034	1,000	1,000	100.00	5.47%	1,000	55	
10		L	11/18/2004	5.90%	2034	700	700	100.00	5.94%	700	42	
11		M	6/1/2005	6.50%	2035	2,000	2,000	100.00	6.55%	2,000	131	
12	Total					12,300				12,300	762	6.20%
13	Prior Year									10,300	631	6.13%
14	Total									22,600	1,394	
15	Mid Year									11,300	697	6.17%
16												
17	**2005 Forecast per Negotiated Settlement**						Net Capital Employed					
18						Principal		Per $100 of		Principal		Average
19			Issue	Coupon	Maturity	Amount	Total	Principal	Effective	Outstanding	Carrying	Embedded
20	Description	Series	Date	Rate	Date	Offered	Amount	Amount	Cost Rate *	31-Dec-03	Cost	Cost Rate
21	LT Adv. - Parent	I	11/6/2001	4.84%	2006	500	500	100.00	4.95%	500	25	
22		H	12/1/2000	6.97%	2008	500	500	100.00	7.05%	500	35	
23		J	11/26/2002	6.15%	2017	7,100	7,100	100.00	6.21%	7,100	441	
24		G	8/12/1999	6.80%	2019	500	500	100.00	6.85%	500	34	
25		K	1/23/2004	5.43%	2034	1,000	1,000	100.00	5.47%	1,000	55	
26		L	11/18/2004	5.90%	2034	700	700	100.00	5.94%	700	42	
27		M	6/1/2005	6.00%	2035	1,843	1,843	100.00	6.00%	1,843	111	
28	Total					12,143				12,143	742	6.11%
29	Prior Year									10,300	631	6.13%
30	Total									22,443	1,373	
31	Mid Year									11,222	687	6.12%

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Schedule of Debt Capital Employed and Embedded Cost
($000's)

2006 Forecast per Application

Description	Series	Issue Date	Coupon Rate	Maturity Date	Principal Amount Offered	Net Capital Employed: Total Amount	Net Capital Employed: Per $100 of Principal Amount	Effective Cost Rate *	Principal Outstanding 31-Dec-03	Carrying Cost	Average Embedded Cost Rate
	H	12/1/2000	6.97%	2008	500	500	100.00	7.05%	500	35	
	J	11/26/2002	6.15%	2017	7,100	7,100	100.00	6.21%	7,100	441	
	G	8/12/1999	6.80%	2019	500	500	100.00	6.85%	500	34	
	K	1/23/2004	5.43%	2034	1,000	1,000	100.00	5.47%	1,000	55	
	L	11/18/2004	5.90%	2034	700	700	100.00	5.94%	700	42	
	M	6/1/2005	6.50%	2035	2,000	2,000	100.00	6.55%	2,000	131	
	N	6/1/2006	6.50%	2036	1,100	1,100	100.00	6.55%	1,100	72	
Total					12,900				12,900	810	6.28%
Prior Year									12,300	762	6.20%
Total									25,200	1,572	
Mid Year									12,600	786	6.24%

2006 Forecast per Negotiated Settlement

Description	Series	Issue Date	Coupon Rate	Maturity Date	Principal Amount Offered	Net Capital Employed: Total Amount	Net Capital Employed: Per $100 of Principal Amount	Effective Cost Rate *	Principal Outstanding 31-Dec-03	Carrying Cost	Average Embedded Cost Rate
	H	12/1/2000	6.97%	2008	500	500	100.00	7.05%	500	35	
	J	11/26/2002	6.15%	2017	7,100	7,100	100.00	6.21%	7,100	441	
	G	8/12/1999	6.80%	2019	500	500	100.00	6.85%	500	34	
	K	1/23/2004	5.43%	2034	1,000	1,000	100.00	5.47%	1,000	55	
	L	11/18/2004	5.90%	2034	700	700	100.00	5.94%	700	42	
	M	6/1/2005	6.00%	2035	1,843	1,843	100.00	6.00%	1,843	111	
	N	6/1/2006	6.25%	2036	1,275	1,275	100.00	6.25%	1,275	80	
Total					12,918				12,918	797	6.17%
Prior Year									12,143	742	6.11%
Total									25,061	1,539	
Mid Year									12,531	769	6.14%

* the effective cost rate includes costs to issue debt.

Schedule 7.5

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Computation of Rate Base
($000s)

Line No.	Description	Cross Ref.	per Application Forecast 2005	per Application Forecast 2006	Negotiated Settlement Forecast 2005	Negotiated Settlement Forecast 2006
1	**Property, Plant and Equipment**					
2	Year end balance	S.7.6 L.7	35,903	37,171	35,903	37,171
3	Deduct:					
4	Accumulated depreciation	S.7.6 L.13	12,212	12,001	11,960	11,499
5	Construction-in-progress		-	-	-	-
6	Total deductions		12,212	12,001	11,960	11,499
7	**Net plant in Service**					
8	Current year-end balance		23,691	25,170	23,943	25,672
9	Previous year-end balance		20,192	23,691	19,912	23,943
10	Total		43,883	48,861	43,855	49,615
11	Mid-year balance		21,942	24,431	21,928	24,808
12	Mid-year rate case expense		(241)	(137)	(241)	(137)
13	Working capital	S.7.9 L.28	640	625	738	626
14	**Gross Rate Base**		22,341	24,919	22,425	25,297
15	Deduct:					
16	**Contributions for extensions**					
17	Current year-end balance		2,331	2,714	2,331	2,714
18	Previous year-end balance		1,951	2,331	1,951	2,331
19	Total		4,282	5,045	4,282	5,045
20	Mid-year balance		2,141	2,522	2,141	2,523
21	**Net Rate Base**	S.7.1 L.5,11,16,22	20,200	22,397	20,284	22,774

Schedule 7.6

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Continuity Schedule of Property, Plant and Equipment
($000)

Line No.	Description	Cross Ref.	per Application Forecast 2005	per Application Forecast 2006	Negotiated Settlement Forecast 2005	Negotiated Settlement Forecast 2006
1	**Property, Plant and Equipment**					
2	Balance at beginning of year		31,507	35,903	31,367	35,903
3	Additions	S.8.1 L.20	4,896	3,028	5,036	3,028
4	Retirement and disposals		(500)	(1,760)	(500)	(1,760)
5	Balance at end of year		35,903	37,171	35,903	37,171
6	Construction-in-progress		-	-	-	-
7	Total Property, Plant and Equipment		35,903	37,171	35,903	37,171
8	**Accumulated Depreciation**					
9	Balance at beginning of year		11,315	12,212	11,315	11,960
10	Depreciation expense	S.6 L.38	1,356	1,509	1,104	1,259
11	Depreciation capitalized		29	30	29	30
12	Retirements and dismantling		(488)	(1,750)	(488)	(1,750)
13	Balance at end of year	S.7.5 L.4	12,212	12,001	11,960	11,499
14	Net Property, Plant and Equipment		23,691	25,170	23,943	25,672

Schedule 7.9

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Computation of Allowance for Working Capital
($000s)

Line No.	Description	Cross Ref.	per Application Forecast 2005	per Application Forecast 2006	Negotiated Settlement Forecast 2005	Negotiated Settlement Forecast 2006
1	Purchased Power	S.1 L.7	22,163	22,572	22,185	22,414
2	Operating and maintenance	S.1 L.8	2,106	2,168	2,077	2,113
3	Taxes other than income	S.1 L.9	736	756	725	740
5	Net O&M		25,005	25,496	24,987	25,267
6	O&M Lag Days		0.19	0.19	0.04	0.04
7	Operating Expenses Working Captial		13	13	3	3
8	Tax installments		453	552	453	342
9	Income Tax Installment Lag Days		15	15	15	15
10	Tax Installments Working Capital		19	23	19	14
11	Income taxes receivable (payable)		(88)	(154)	122	(76)
12	Tax Payable Lag Days		242	242	242	242
13	Taxes Payable Working Captial		(58)	(102)	81	(50)
14	Inventory (Three year average)		570	590	570	590
15	GST Impact on working capital	S.7.10 L.26	5	0	4	(1)
16	Return - Long Term Debt		740	829	726	818
17	Combined Long Term Debt Lag Days		(50)	(50)	(50)	(50)
18	Long Term Debt Working Captial		(101)	(114)	(99)	(112)
19	Return - 50% of Common Equity		430	477	402	451
20	Dividend Lag Days		(4)	(4)	(4)	(4)
21	Common Equity (Dividend) Working Capital		(5)	(5)	(5)	(5)
22	Return - 50% of Common Equity		430	477	402	451
23	Depreciation Lag Days		42	42	42	42
24	Common Equity (Retained Earnings) Working Capital		49	55	46	52
25	Net Depreciation		1,287	1,430	1,035	1,180
26	Depreciation Lag Days		42	42	42	42
27	Depreciation Working Capital		148	165	119	136
28	Working capital	S.7.5 L.13	640	625	738	626

Schedule 7.10

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Effect of GST on Working Captial
($000s)

Line No.	Description	Cross Ref.		per Application Forecast 2005	per Application Forecast 2006	Negotiated Settlement Forecast 2005	Negotiated Settlement Forecast 2006
1	REVENUE:						
2	Total Operating Revenue Subject to GST			27,539	28,073	27,564	27,947
3	GST Rate			7.00%	7.00%	7.00%	7.00%
4	GST Billable		(a)	1,928	1,965	1,929	1,956
5	Day Factor - Revenues			41.6	41.6	41.5	41.5
6	Day Factor - Remittance Lag			55	55	55	55
7			(b)	(13)	(13)	(14)	(14)
8	GST Impact on Working Capital Increase/(Decrease)		(a)*(b)/365	(71)	(72)	(72)	(73)
9	EXPENSES:						
10	Total Utility Expenses			28,373	29,333	27,827	28,520
11	Taxes other than Income			(736)	(756)	(725)	(740)
12	Labour and Fringe			(1,529)	(1,561)	(1,529)	(1,561)
13	Depreciation			(1,356)	(1,509)	(1,104)	(1,259)
14	Amortization of contributions			69	79	69	79
15	Income Tax			(536)	(678)	(327)	(404)
16	Rate Case Provision			54	54	54	54
17	Rate Case Claims			100	-	100	-
18	Captial Expenditures			4,896	3,028	4,896	3,028
19	Net Costs Subject to GST			29,335	27,990	29,261	27,717
20	GST Rate			7.00%	7.00%	7.00%	7.00%
21	GST Refundable		(c)	2,053	1,959	2,048	1,940
22	Day Factor - Expense (Including Capital)			41.5	41.5	41.5	41.5
23	Day Factor - Remittance Lag			55	55	55	55
24			(d)	14	14	14	14
25	GST Impact on Working Capital Increase/(Decrease)		(c)*(d)/365	76	72	76	72
26	Net Impact of GST on Working Captial	S.7.9 L.15		5	0	4	(1)

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Plant Additions
($000s)

Schedule 8.1

Line No.	Description	Cross Ref.	per Application Forecast 2005	per Application Forecast 2006	Negotiated Settlement Forecast 2005	Negotiated Settlement Forecast 2006
1	Work in progress, beginning of year		-	-	140	-
2	**Distribution:**					
3	New Extensions		765	759	765	759
4	25kV Substations & Conversions		3,544	1,759	3,544	1,759
5	Distribution Improvements		150	150	150	150
6	Street and Sentinel Lights		209	190	209	190
7	Meters		45	50	45	50
8	Transformers and Regulators		50	55	50	55
9	Oracle Savings		(11)	(12)	(11)	(12)
			4,752	2,951	4,752	2,951
10	**General property and equipment:**					
11	Tools, Instruments & Equipment		48	30	48	30
12	Office Furniture & Equipment		2	2	2	2
13	Office Computer Equipment		10	8	10	8
14	Computer Software		38	-	38	-
15	Communication Equipment		5	2	5	2
16	Transportation Equipment		40	50	40	50
17	Land and Buildings		30	15	30	15
			173	107	173	107
18	Miscellaneous Other		(29)	(30)	(29)	(30)
19	**Total capital expenditures**		4,896	3,028	4,896	3,028
20	Less: Transfers to rate base	S.7.6 L 3	(4,896)	(3,028)	(5,036)	(3,028)
21	Work in progress, end of year		-	-	-	-

Northland Utilities (Yellowknife) Limited
2005 - 2006 General Rate Application
Income Tax Expense
($000s)

Schedule 9

Line No.	Description	Cross Ref.	per Application Forecast 2005	per Application Forecast 2006	Negotiated Settlement Forecast 2005	Negotiated Settlement Forecast 2006
1	Utility earnings before tax		1,395	1,632	1,133	1,300
2	**Add:**					
3	Depreciation	S.1 L.11	1,356	1,509	1,104	1,259
4	Amortization of contributions	S.1 L.12	(69)	(79)	(69)	(79)
5	Non-allowable expenses		10	10	10	10
6	Rate case write-off	S.1 L.7	(54)	(54)	(54)	(54)
7	Charges to deferred pension	S.7.4 L.18	34	35	34	35
8	Sub-total		1,277	1,421	1,025	1,171
9						
10	**Deduct:**					
11	CCA		939	1,014	1,021	1,214
12	CEC		3	3	3	3
13	Rate Case Expenditure		100	-	100	-
14	Pension capitalized		12	13	12	13
15	ES&G		196	170	196	170
16	Sub-total		1,250	1,200	1,332	1,400
17						
18	Taxable income		1,422	1,853	826	1,071
19	Tax rate (21% Federal, 14.00% NWT)		35.00%	35.00%	35.00%	35.00%
20	Income tax		498	649	289	375
21	Large corporation tax (incl. Corp surtax)		38	29	38	29
22	Prior year (over)/under provision		-	-	-	-
23						
24	Total current provision	S.1 L.14	536	678	327	404

Northland Utilities (Yellowknife) Limited
2005 GRA
Cost of Service Study

Table of Contents

Northland Utilities (Yellowknife) Limited
2005 GRA
Comparison of Costs and Revenues
2005

	Forecast Costs ($000)	Forecast Revenue ($000)	Revenue / Cost Ratio (%)	Surplus/ (Shortfall) ($000)	Revenue Increase (%)
Costs and Revenues at Existing Rates					
Residential	10,813.4	10,287.7	95.1%	(525.7)	
General Service	16,078.1	16,581.1	103.1%	502.9	
Street Lights	610.1	679.2	111.3%	69.1	
Space Lights	14.9	15.9	106.9%	1.0	
Total Allocated Cost/ Revenue	27,516.5	27,563.9	100.2%	47.4	
Costs and Proposed Revenues					
Residential	10,820.5	10,292.1	95.1%	(528.4)	0.0%
General Service	16,090.3	16,615.1	103.3%	524.8	0.2%
Street Lights	609.0	612.5	100.6%	3.6	-9.8%
Space Lights	14.9	14.9	100.0%	(0.0)	-6.5%
Total Allocated Cost/ Revenue	27,534.7	27,534.7	100.0%	(0.0)	-0.1%
Forecast Growth in Unbilled Revenue		0.0		0.0	
Costs and Revenues At Proposed Rates Considering Unbilled					
Residential	10,820.5	10,292.1	95.1%	(528.4)	0.0%
General Service	16,090.3	16,615.1	103.3%	524.8	0.0%
Street Lights	609.0	612.5	100.6%	3.6	0.0%
Space Lights	14.9	14.9	100.0%	(0.0)	0.0%
Total Allocated Cost/ Revenue	27,534.7	27,534.7	100.0%	(0.0)	0.0%

Mid-year Balance of Gross Plant, Property & Equipment - 2005

Yellowknife		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Diesel	0.0	0.0	0.0	0.0
Plant	- Wind	0.0	0.0	0.0	0.0
	Production Total	0.0	0.0	0.0	0.0
		------	------	------	------
Transmission		0.0	0.0	0.0	0.0
Plant	Transmission Total	0.0	0.0	0.0	0.0
		------	------	------	------
Distribution Plant [1]		14,660.9	15,238.5	0.0	29,899.4
General Plant		1,867.2	1,940.8	0.0	3,808.0
	Gross PP & E Total	16,528.1	17,179.3	0.0	33,707.4
		======	======	======	======

Notes

		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
[1] Distribution Plant by Rate Class					
	Residential	9,219.4	6,471.2	0.0	15,690.5
	General Service	2,376.0	8,596.5	0.0	10,972.5
	Street Lights	3,052.3	163.1	0.0	3,215.4
	Space Lights	13.2	7.8	0.0	21.0
		------	------	------	------
	Total	14,660.9	15,238.5	0.0	29,899.4
		======	======	======	======

Northland Utilities (Yellowknife) Limited
2005 GRA

Summary of Mid-Year Net Rate Base
2005

Yellowknife		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Mid-year Net Rate Base					
Production	- Diesel	0.0	0.0	0.0	0.0
Plant	- Wind	0.0	0.0	0.0	0.0
	Production Total	0.0	0.0	0.0	0.0
		------	------	------	------
Transmission	- Other Lines	0.0	0.0	0.0	0.0
Plant	Transmission Total	0.0	0.0	0.0	0.0
		------	------	------	------
Distribution Plant [1]		8,403.8	8,776.1	0.0	17,179.9
General Plant		1,277.7	1,328.0	0.0	2,605.7
		------	------	------	------
Fixed Assets Total		9,681.5	10,104.1	0.0	19,785.6
		======	======	======	======
Reserves and Deferred Items					
Reserves and Deferred Total					0.0
					======
Working Capital &					
Special Regulatory Items					
Working Capital					737.7
Rate Case Expense (mid-year)					(241.0)
	Total				496.7
					======
MID-YEAR NET RATE BASE					20,282.3
					======

Notes

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[1] Distribution Plant by Rate Class	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Residential	5,287.6	3,726.8	0.0	9,014.5
General Service	1,365.8	4,950.8	0.0	6,316.6
Street Lights	1,742.9	93.9	0.0	1,836.8
Space Lights	7.5	4.5	0.0	12.0
	------	------	------	------
Total	8,403.8	8,776.1	0.0	17,179.9
	======	======	======	======

Northland Utilities (Yellowknife) Limited
2005 GRA
Summary of Service Costs - 2005

		Forecast Cost ($000)
Carrying Cost of Investment		
	Depreciation	1,104.0
	Municipal Taxes	48.5
	Franchise Taxes	676.5
	Return on Ratebase	1,532.0
	Income Taxes (less non-utility taxes)	327.0
	Amortization of Contribution	(69.0)

	Total Carrying Cost	3,619.0

Operating Expenses		
	Fuel & Purchased Power	22,185.0
	Transmission	0.0
	Distribution	518.7
	Administrative General	600.1
	Customer Accounting	655.1
	Marketing	112.3
	General Expense	95.4
	Risk Insurance	33.4
	PL & PD	7.7

	Total Operating Expense	24,207.7

Credit to Expense		
	Service Revenue	(30.0)
	Rental & Misc. Revenue	(226.0)
	Penalty	(36.0)

	Total Credit	(292.0)

Total Service Cost		27,534.7
		======

Northland Utilities (Yellowknife) Limited
2005 GRA
Classifying Depreciation to Customer, Demand and Energy - 2005
(Based on Mid-year Balance of Gross Plant, Property & Equipment)

Yellowknife		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Diesel	0.0	0.0	0.0	0.0
Plant	- Wind	0.0	0.0	0.0	0.0
	Production Total	0.0	0.0	0.0	0.0
		------	------	------	------
Transmission		0.0	0.0	0.0	0.0
Plant	Transmission Total	0.0	0.0	0.0	0.0
		------	------	------	------
Distribution Plant		472.7	491.3	0.0	964.0
General Plant		68.6	71.4	0.0	140.0
	Depreciation Provision	541.3	562.7	0.0	1,104.0
		======	======	======	======

Northland Utilities (Yellowknife) Limited
2005 GRA
Classifying Municipal Taxes to Customer, Demand and Energy - 2005
(Based on Mid-year Balance of Gross Plant, Property & Equipment)

Yellowknife		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Diesel	0.0	0.0	0.0	0.0
Plant	- Wind	0.0	0.0	0.0	0.0
	Production Total	0.0	0.0	0.0	0.0
		------	------	------	------
Transmission		0.0	0.0	0.0	0.0
Plant	Transmission Total	0.0	0.0	0.0	0.0
		------	------	------	------
Distribution Plant		21.1	21.9	0.0	43.1
General Plant		2.7	2.8	0.0	5.5
	Municipal and Franchise Taxes	23.8	24.7	0.0	48.5
		======	======	======	======

Northland Utilities (Yellowknife) Limited
2005 GRA

Classifying Return to Customer, Demand and Energy - 2005
(Based on Mid-year Net Rate Base)

Yellowknife		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Diesel	0.0	0.0	0.0	0.0
Plant	- Wind	0.0	0.0	0.0	0.0
	Production Total	0.0	0.0	0.0	0.0
Transmission		0.0	0.0	0.0	0.0
Plant	Transmission Total	0.0	0.0	0.0	0.0
		------	------	------	------
Distribution Plant		634.8	662.9	0.0	1,297.7
General Plant		96.5	100.3	0.0	196.8
		------	------	------	------
Fixed Assets Total		731.3	763.2	0.0	1,494.5
		======	======	======	======
Reserves and Deferred Items					
Reserves and Deferred Total					0.0

Working Capital & Special Regulatory Items					
Working Capital					55.7
Rate Case Expense (mid-year)					(18.2)
	Total				37.5

Return Total					1,532.0
					======

Northland Utilities (Yellowknife) Limited
2005 GRA

Classifying Income Tax to Customer, Demand and Energy - 2005
(Based on Mid-year Net Rate Base)

Yellowknife		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Diesel	0.0	0.0	0.0	0.0
Plant	- Wind	0.0	0.0	0.0	0.0
	Production Total	0.0	0.0	0.0	0.0
Transmission		0.0	0.0	0.0	0.0
Plant	Transmission Total	0.0	0.0	0.0	0.0
		------	------	------	------
Distribution Plant		135.5	141.5	0.0	277.0
General Plant		20.6	21.4	0.0	42.0
		------	------	------	------
Fixed Assets Total		156.1	162.9	0.0	319.0
		======	======	======	======
Reserves and Deferred Items					
Reserves and Deferred Total					0.0
					======
Working Capital & Special Regulatory Items					
Working Capital					11.9
Rate Case Expense (mid-year)					(3.9)
	Total				8.0
					======
Income Tax Total					327.0
					======

Northland Utilities (Yellowknife) Limited
2005 GRA
Classifying Carrying Cost of General Plant to Customer,
Demand and Energy - 2005

(Based on Mid-year Balance of Gross Plant, Property & Equipment
Without General Plant)

Yellowknife		($000)
	Depreciation	140.0
	Municipal Tax	5.5
	Return	196.8
	Income Tax	42.0
	O & M	95.4

	Total	479.7
		======

Yellowknife		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production Plant	- Diesel	0.0	0.0	0.0	0.0
	- Wind	0.0	0.0	0.0	0.0
	Production Total	0.0	0.0	0.0	0.0
		------	------	------	------
Transmission Plant		0.0	0.0	0.0	0.0
	Transmission Total	0.0	0.0	0.0	0.0
		------	------	------	------
Distribution Plant		235.2	244.5	0.0	479.7
	General Plant Carrying Cost	235.2	244.5	0.0	479.7
		======	======	======	======

Northland Utilities (Yellowknife) Limited
2005 GRA
Classifying Carrying Cost of Working Capital to Customer, Demand and Energy - 2005

(Based on Mid-year Balance of Gross Plant, Property & Equipment Without General Plant)

Yellowknife		($000)
	Return	55.7
	Income Tax	11.9

		67.6
		======

Combined Yellowknife		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Diesel	0.0	0.0	0.0	0.0
Plant	- Wind	0.0	0.0	0.0	0.0
	Production Total	0.0	0.0	0.0	0.0
		------	------	------	------
Transmission		0.0	0.0	0.0	0.0
Plant	Transmission Total	0.0	0.0	0.0	0.0
		------	------	------	------
Distribution Plant		33.2	34.5	0.0	67.6
	Working Capital Carrying Cost	33.2	34.5	0.0	67.6
		======	======	======	======

Northland Utilities (Yellowknife) Limited
2005 GRA
Classifying Carrying Cost of Rate Case Expense to Customer, Demand and Energy - 2005

(Based on Mid-year Balance of Gross Plant, Property & Equipment Without General Plant)

Yellowknife		($000)
	Return	(18.2)
	Income Tax	(3.9)

		(22.1)
		======

Combined Yellowknife		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Diesel	0.0	0.0	0.0	0.0
Plant	- Wind	0.0	0.0	0.0	0.0
	Production Total	0.0	0.0	0.0	0.0
		------	------	------	------
Transmission		0.0	0.0	0.0	0.0
Plant	Transmission Total	0.0	0.0	0.0	0.0
		------	------	------	------
Distribution Plant		(10.8)	(11.3)	0.0	(22.1)
	Rate Case Expense Carrying Cost	(10.8)	(11.3)	0.0	(22.1)
		======	======	======	======

Northland Utilities (Yellowknife) Limited
2005 GRA
Classifying Operation and Maintenance Expenses
to Customer, Demand and Energy - 2005

Yellowknife	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)	
Production O&M (Wind)	0.0	0.0	0.0	0.0	
Production O&M (Excl Fuel & Pur Pwr)	0.0	0.0	0.0	0.0	
Fuel & Purchased Power	0.0	0.0	22,185.0	22,185.0	
Transmission - Transmission Line	0.0	0.0	0.0	0.0	
Transmission - Other Lines	0.0	0.0	0.0	0.0	
Transmission - Spare Line	0.0	0.0	0.0	0.0	
Distribution (Excl Lights and Brushing)	193.4	254.1	0.0	447.5	(1)
Distribution (Brushing)	14.8	15.9	0.0	30.8	(2)
Distribution (Street and Space Lights)	40.5	0.0	0.0	40.5	(3)
Administrative General				600.1	
Customer Accounting	655.1	0.0	0.0	655.1	
Marketing	112.3	0.0	0.0	112.3	
General Plant				95.4	
Risk Insurance				33.4	
Public Liability & Property Damage	0.0	0.0	7.7	7.7	

Total O & M				24,207.7	
				======	

Notes

(1) Based on Classified Distr. Gross PP&E
(2) Based on Classified Distr. Gross PP&E (Poles, O/H Cond., Transf only)
(3) Based on Classified Distr. Gross PP&E

Northland Utilities (Yellowknife) Limited
2005 GRA
Classifying Risk Insurance Expenses
to Customer, Demand and Energy - 2005

(Based on Mid-year Balance of Gross Plant, Property & Equipment
Without General Plant)

Yellowknife		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Production	- Diesel	0.0	0.0	0.0	0.0
Plant	- Wind	0.0	0.0	0.0	0.0
	Production Total	0.0	0.0	0.0	0.0
		------	------	------	------
Transmission		0.0	0.0	0.0	0.0
Plant	Transmission Total	0.0	0.0	0.0	0.0
		------	------	------	------
Distribution Plant		16.4	17.0	0.0	33.4
		------	------	------	------
	Risk Insurance Expenses	16.4	17.0	0.0	33.4
		======	======	======	======

Northland Utilities (Yellowknife) Limited
2005 GRA
Classifying Revenue Offsets
to Customer, Demand and Energy - 2005

(Based on Sum of All Service Costs Excluding Administrative & General and Public Liability & Public Damage)

Sum of Service Costs (Excl A&G, Revenue Offsets and PLPD) Yellowknife		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
	Production Total	0.0	0.0	22,185.0	22,185.0
Transmission		0.0	0.0	0.0	0.0
Plant	Transmission Total	0.0	0.0	0.0	0.0
Distribution Plant		2,554.0	1,872.4	0.0	4,426.4
	Sum of Service Costs Excluding A&G and PLPD	2,554.0	1,872.4	22,185.0	26,611.4

Classified Revenue Offsets Yellowknife		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
	Production Total	0.0	0.0	(243.4)	(243.4)
Transmission		0.0	0.0	0.0	0.0
Plant	Transmission Total	0.0	0.0	0.0	0.0
Distribution Plant		(28.0)	(20.5)	0.0	(48.6)
	Revenue Offsets	(28.0)	(20.5)	(243.4)	(292.0)

Northland Utilities (Yellowknife) Limited
2005 GRA
Classifying Administrative & General Expenses
to Customer, Demand and Energy - 2005

(Based on Sum of All Service Costs Including Revenue Offsets but Excluding Public Liability & Public Damage)

Sum of Service Costs (Incl Revenue Offset, Excl A&G, Excl PLPD) Yellowknife		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
	Production Total	0.0	0.0	21,941.6	21,941.6
Transmission		0.0	0.0	0.0	0.0
Plant	Transmission Total	0.0	0.0	0.0	0.0
Distribution Plant		2,526.0	1,851.8	0.0	4,377.8
	Sum of Service Costs Incl Rev Offsets, Excl PLPD	2,526.0	1,851.8	21,941.6	26,319.4

Classified A & G Yellowknife		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
	Production Total	0.0	0.0	500.3	500.3
Transmission		0.0	0.0	0.0	0.0
Plant	Transmission Total	0.0	0.0	0.0	0.0
Distribution Plant		57.6	42.2	0.0	99.8
	Administrative & General Expenses	57.6	42.2	500.3	600.1

Northland Utilities (Yellowknife) Limited
2005 GRA

Classifying Amortization of Transmission & Distribution Contributions to Customer, Demand and Energy - 2005

(Based on Mid-year Depreciation)

	2005 Total ($000)
Amortization of Distribution Contributions	
Residential	(25.7)
General Service	(41.6)
Street Lights	(1.7)
Space Lights	0.0
Total	(69.0)

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Distribution				
Mid-year Depreciation (based on Gross PP&E)				
Residential	297.2	208.6	0.0	505.9
General Service	76.6	277.2	0.0	353.8
Street Lights	98.4	5.3	0.0	103.7
Space Lights	0.4	0.3	0.0	0.7
Total	472.7	491.3	0.0	964.0
Allocated Amortization of Contributions				
Residential	(15.1)	(10.6)	0.0	(25.7)
General Service	(9.0)	(32.6)	0.0	(41.6)
Street Lights	(1.6)	(0.1)	0.0	(1.7)
Space Lights	0.0	0.0	0.0	0.0
Total Distributio	(25.7)	(43.3)	0.0	(69.0)

Northland Utilities (Yellowknife) Limited
2005 GRA

Allocation of Direct Purchase Power Costs - 2005

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Depreciation	0.0	0.0	0.0	0.0
Municipal and Franchise Taxes	0.0	0.0	0.0	0.0
Return on Ratebase	0.0	0.0	0.0	0.0
Income Taxes	0.0	0.0	0.0	0.0
General Plant Carrying Costs	0.0	0.0	0.0	0.0
Working Capital Carrying Costs	0.0	0.0	0.0	0.0
Rate Case Expense Carrying Costs	0.0	0.0	0.0	0.0
Fuel & Purchased Power	0.0	0.0	22,185.0	22,185.0
Risk Insurance	0.0	0.0	0.0	0.0
Revenue Offsets	0.0	0.0	(243.4)	(243.4)
Administrative General	0.0	0.0	500.3	500.3
Amortization of Contribution to Prod. Facilities	0.0	0.0	0.0	0.0
	------	------	------	------
Total	0.0	0.0	22,441.9	22,441.9
	======	======	======	======

Allocated Costs	Demand Cost Allocator: Coincidental Peak (kW)	Share of Demand Cost ($000)	Energy Cost Allocator: Energy Sent Out (MWh)	Share of Energy Cost ($000)	Total Cost ($000)
Residential	13,790	0.0	61,863	8027.9	8,027.9
General Service	16,174	0.0	109,364	14192.0	14,192.0
Street Lights	397	0.0	1,632	211.8	211.8
Space Lights	19	0.0	79	10.2	10.2
	------	------	------	------	------
Total	30,380	0.0	172,938	22,441.9	22,441.9
	======	======	======	======	======
Unit Cost		$0.00 /kW		12.98	cents/kWh

Northland Utilities (Yellowknife) Limited
2005 GRA

Allocation of Distribution Return and Income Tax to Rate Class - 2005
(Based on Mid-year Balance of Net Distribution Rate Base)

		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Distribution Carrying Costs					
Return		634.8	662.9	0.0	1,297.7
Income Tax		135.5	141.5	0.0	277.0
		------	------	------	------
	Total	770.3	804.4	0.0	1,574.6
		======	======	======	======
Allocated Costs					
Residential		484.6	341.6	0.0	826.2
General Service		125.2	453.8	0.0	579.0
Street Lights		159.7	8.6	0.0	168.4
Space Lights		0.7	0.4	0.0	1.1
		------	------	------	------
	Total	770.3	804.4	0.0	1,574.6
		======	======	======	======

Northland Utilities (Yellowknife) Limited
2005 GRA

Allocation of Distribution Carrying Costs (Excluding Return and Income Tax)
to Rate Class - 2005

(Based on Mid-year Balance of Gross Distribution Plant, Property & Equipment)

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Distribution Carrying Costs				
Depreciation	472.7	491.3	0.0	964.0
Municipal Taxes	21.1	21.9	0.0	43.1
General Plant Carrying Costs	235.2	244.5	0.0	479.7
Working Capital Carrying Costs	33.2	34.5	0.0	67.6
Rate Case Expense Carrying Costs	(10.8)	(11.3)	0.0	(22.1)
	------	------	------	------
Total	751.3	780.9	0.0	1,532.3
	======	======	======	======

	Revenue Allocation	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Franchise Taxes					
Residential	10,039.3	35.2	0.0	217.7	252.853
General Service	16,207.0	0.0	61.8	346.4	408.194
Street Lights	597.5	15.0	0.0	0.0	15.0
Space Lights	14.5	0.4	0.0	0.0	0.4
	------	------	------	------	------
Total	26,858.2	50.6	61.8	564.1	676.5
	======	======	======	======	======

	Customer	Demand	Energy	Total
Total Allocated Carrying Costs				
Residential	507.7	331.6	217.7	1,057.0
General Service	121.8	502.3	346.4	970.5
Street Lights	171.5	8.4	0.0	179.8
Space Lights	1.0	0.4	0.0	1.4
	------	------	------	------
Total	802.0	842.7	564.1	2,208.7
	======	======	======	======

Northland Utilities (Yellowknife) Limited
2005 GRA

Allocation of Distribution Operating & Maintenance Costs
to Rate Class - 2005

(Based on Mid-year Balance of Gross Distribution Plant, Property & Equipment)

	Customer [1] ($000)	Demand ($000)	Energy ($000)	Total ($000)
Distribution O&M (Excl Lights and Brushing)	193.4	254.1	0.0	447.5
Distribution O&M (Brushing)	14.8	15.9	0.0	30.8
Distribution (Street and Space Lights)	40.5	0.0	0.0	40.5
	------	------	------	------
Total	248.7	270.0	0.0	518.7
	======	======	======	======
Allocated Distribution O&M				
Residential	165.5	114.7	0.0	280.1
General Service	42.7	152.3	0.0	195.1
Street Lights	38.6	2.9	0.0	41.5
Space Lights	1.9	0.1	0.0	2.0
	------	------	------	------
Total	248.7	270.0	0.0	518.7
	======	======	======	======

Note: (1) Brushing portion of Customer Cost are allocated to Rate Class without Street and Space Lights based on Gross Distribution Plant, Property and Equipment for Poles, Towers & Fixtures and Overhead Conductors.

All remaining Customer Cost (excluding Street and Space Lights) are allocated to Rate Class without Street Lights and Space Lights based on Gross Distribution Plant, Property and Equipment without Street Lights and Space Lights which are directly allocated.

Northland Utilities (Yellowknife) Limited
2005 GRA

Allocation of Customer Accounting and Marketing Costs to Rate Class - 2005

(Based on Average Number of Customers Excluding Street Lights and Space Lights and Energy Sales)

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Customer Accounting	655.1	0.0	0.0	655.1
Marketing	112.3	0.0	0.0	112.3
	------	------	------	------
Total	767.4	0.0	0.0	767.4
	======	======	======	======

Customer Accounting	98% of Cost Allocated Based on Avg No. of Customers 2% of Cost Allocated Based on Energy Sale
Marketing	15% of Cost Allocated Based on Avg No. of Customers 85% of Cost Allocated Based on Energy Sale

Allocated Customer Accounting and Marketing Costs	Customer	Demand	Energy	Total
Residential	605.7	0.0	0.0	605.7
General Service	160.6	0.0	0.0	160.6
Street Lights	1.0	0.0	0.0	1.0
Space Lights	0.0	0.0	0.0	0.0
	------	------	------	------
Total	767.4	0.0	0.0	767.4
	======	======	======	======

Northland Utilities (Yellowknife) Limited
2005 GRA

Allocation of Risk Insurance and PLPD [1] Insurance Expenses
to Rate Class - 2005

(Risk Insurance Based on Mid-year Gross Distribution Plant, Property and Equipment;
PLPD Insurance Based on Energy Sales)

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Risk Insurance	16.4	17.0	0.0	33.4
PLPD Insurance	0.0	0.0	7.7	7.7
	------	------	------	------
Total	16.4	17.0	7.7	41.1
	======	======	======	======
Allocated Risk and PLPD Insurance Costs				
Residential	10.3	7.2	2.8	20.3
General Service	2.7	9.6	4.9	17.1
Street Lights	3.4	0.2	0.1	3.7
Space Lights	0.0	0.0	0.0	0.0
	------	------	------	------
Total	16.4	17.0	7.7	41.1
	======	======	======	======

Note: (1) Public Liability and Property Damage

Northland Utilities (Yellowknife) Limited
2005 GRA

Allocation of Revenue Offsets
to Rate Class - 2005

(Based on Sum of All Service Costs Excluding Administrative & General and Public Liability & Public Damage)

		Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Revenue Offsets		(28.0)	(20.5)	0.0	(48.6)
		------	------	------	------
	Total	(28.0)	(20.5)	0.0	(48.6)
		======	======	======	======
Allocated Sum of Service Costs Excluding A&G and PLPD					
Residential		1,773.8	795.1	217.7	2,786.5
General Service		452.9	1,118.0	346.4	1,917.4
Street Lights		374.2	20.0	0.0	394.3
Space Lights		3.7	1.0	0.0	4.6
		------	------	------	------
	Total	2,604.6	1,934.1	564.1	5,102.8
		======	======	======	======
Allocated Revenue Offsets					
Residential		(19.1)	(8.4)	0.0	(27.5)
General Service		(4.9)	(11.9)	0.0	(16.7)
Street Lights		(4.0)	(0.2)	0.0	(4.2)
Space Lights		(0.0)	(0.0)	0.0	(0.0)
		------	------	------	------
	Total	(28.0)	(20.5)	0.0	(48.6)
		======	======	======	======

Northland Utilities (Yellowknife) Limited
2005 GRA

Allocation of Administrative & General Expenses
to Rate Class - 2005

(Based on Sum of All Service Costs Excluding Administrative & General and Public Liability & Public Damage but Including Revenue Offsets)

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Administrative & General Expenses	57.6	42.2	0.0	99.8
	------	------	------	------
Total	57.6	42.2	0.0	99.8
	======	======	======	======
<u>Allocated Sum of Service Costs</u>				
<u>Excl A&G and PLPD; Incl Revenue Offset</u>				
Residential	1,754.7	786.7	217.7	2,759.0
General Service	448.1	1,106.1	346.4	1,900.6
Street Lights	370.2	19.8	0.0	390.0
Space Lights	3.6	0.9	0.0	4.6
	------	------	------	------
Total	2,576.6	1,913.6	564.1	5,054.3
	======	======	======	======
<u>Allocated Administrative & General Expenses</u>				
Residential	39.2	17.4	0.0	56.6
General Service	10.0	24.4	0.0	34.4
Street Lights	8.3	0.4	0.0	8.7
Space Lights	0.1	0.0	0.0	0.1
	------	------	------	------
Total	57.6	42.2	0.0	99.8
	======	======	======	======

Northland Utilities (Yellowknife) Limited
2005 GRA

Summary of Fully Allocated Costs by Rate Class: Residential
2005

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Purchased Power	0.0	0.0	8,027.9	8,027.9
Transmission - Transmission Line	0.0	0.0	0.0	0.0
Transmission	0.0	0.0	0.0	0.0
Distribution				
Return and Income Tax	484.6	341.6	0.0	826.2
Carrying Costs (Excluding Return and Income Tax)	507.7	331.6	217.7	1,057.0
Operating & Maintenance Costs	165.5	114.7	0.0	280.1
Customer Accounting & Marketing	605.7	0.0	0.0	605.7
Risk Insurance and PLPD	10.3	7.2	2.8	20.3
Revenue Offsets	(19.1)	(8.4)	0.0	(27.5)
Administrative & General	39.2	17.4	0.0	56.6
Amortization of Contributions	(15.1)	(10.6)	0.0	(25.7)
Total	1,778.8	793.4	8,248.3	10,820.5
Unit Cost	274.89 $/customer	61.84 $/kW	14.13 c/kWh	

Northland Utilities (Yellowknife) Limited
2005 GRA

Summary of Fully Allocated Costs by Rate Class: General Service
2005

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Purchased power	0.0	0.0	14,192.0	14,192.0
Distribution				
Return and Income Tax	125.2	453.8	0.0	579.0
Carrying Costs (Excluding Return and Income Tax)	121.8	502.3	346.4	970.5
Operating & Maintenance Costs	42.7	152.3	0.0	195.1
Customer Accounting & Marketing	160.6	0.0	0.0	160.6
Risk Insurance and PLPD	2.7	9.6	4.9	17.1
Revenue Offsets	(4.9)	(11.9)	0.0	(16.7)
Administrative & General	10.0	24.4	0.0	34.4
Amortization of Contributions	(9.0)	(32.6)	0.0	(41.6)
Total	449.1	1,098.0	14,543.3	16,090.3
Unit Cost	427.70 $/customer	72.96 $/kW	14.10 c/kWh	

Northland Utilities (Yellowknife) Limited
2005 GRA

Summary of Fully Allocated Costs by Rate Class: Street Lights
2005

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Purchased power	0.0	0.0	211.8	211.8
Distribution				
Return and Income Tax	159.7	8.6	0.0	168.4
Carrying Costs (Excluding Return and Income Tax)	171.5	8.4	0.0	179.8
Operating & Maintenance Costs	38.6	2.9	0.0	41.5
Customer Accounting & Marketing	1.0	0.0	0.0	1.0
Risk Insurance and PLPD	3.4	0.2	0.1	3.7
Revenue Offsets	(4.0)	(0.2)	0.0	(4.2)
Administrative & General	8.3	0.4	0.0	8.7
Amortization of Contributions	(1.6)	(0.1)	0.0	(1.7)
	------	------	------	------
Total	376.9	20.2	211.9	609.0
	======	======	======	======
Unit Cost		54.68 $/kW	13.76 c/kWh	

Northland Utilities (Yellowknife) Limited
2005 GRA

Summary of Fully Allocated Costs by Rate Class: Space Lights
2005

	Customer ($000)	Demand ($000)	Energy ($000)	Total ($000)
Purchased power	0.0	0.0	10.2	10.2
Distribution				
Return and Income Tax	0.7	0.4	0.0	1.1
Carrying Costs (Excluding Return and Income Tax)	1.0	0.4	0.0	1.4
Operating & Maintenance Costs	1.9	0.1	0.0	2.0
Customer Accounting & Marketing	0.0	0.0	0.0	0.0
Risk Insurance and PLPD	0.0	0.0	0.0	0.0
Revenue Offsets	(0.0)	(0.0)	0.0	(0.0)
Administrative & General	0.1	0.0	0.0	0.1
Amortization of Contributions	0.0	0.0	0.0	0.0
	------	------	------	------
Total	3.7	1.0	10.2	14.9
	======	======	======	======
Unit Cost		53.88 $/kW	13.76 c/kWh	

Northland Utilities (Yellowknife) Limited
2005 GRA

Summary of Customers, Demand, and Energy for Allocation Purposes
2005

Number of Customers	
Residential	6,471
General Service	1,050
Street Lights	n/a
Space Lights	n/a

Total	7,521
	======

NCP at Distribution Level (kW)	
Residential	15,752
General Service	20,925
Street Lights	397
Space Lights	19

Total	37,093
	======

Energy Supply (MW.h)	
Residential	61,863
General Service	109,364
Street Lights	1,632
Space Lights	79

Total	172,938
	======

Energy, Demand, and Loss Analysis

An Energy, Demand, and Loss Analysis was required for the development of annual energy and NCP demand cost allocators. In this analysis:

- Forecast annual energy losses were allocated to each rate class;
- Coincident peak (CP) demand at the customer level and CP demand losses were determined for each rate class as a basis for the calculation of NCP demand losses for each rate class;
- Non-coincident peak (NCP) demand at the customer level and NCP demand losses were calculated for each rate class.

Classification of Assets to Customer, Demand and Energy

	Customer %	Demand %	Energy %
Production			
Specific Hydro	0%	0%	100%
Other Hydro	0%	40%	60%
Diesel	0%	100%	0%
Wind	0%	0%	100%
Transmission			
Specific Line	0%	100%	0%
All other Transmission Lines	0%	100%	0%
Distribution			
Land & Rights, Sub Equipments	0%	100%	0%
Poles, Towers and Fixtures	75%	25%	0%
O/H Conductors & Line Transformers	30%	70%	0%
Services	100%	0%	0%
Meters and Metering Equipments	100%	0%	0%
Street Lights	100%	0%	0%
Space Lights	100%	0%	0%

Classification of Working Capital to Customer, Demand and Energy

Production	
O & M	Based on Classified Prod O&M Exp Excl Fuel
Taxes	Based on Gross Production PP & E
Fuel	100% Energy Production
Distribution	Based on Gross Distribution PP & E
Marketing & Customer Accounting	100% Customer Service
General Plant	Based on Gross General Plant PP & E
A & G	Based Total Classified Working Capital before A&G

Classification of Carrying Costs of Special Regulatory Items to Customer, Demand and Energy

	Customer %	Demand %	Energy %
Deferred Expenses - Production Specific	Based on Mid-year Gross	Production PP & E	
Deferred Expenses - Transmission Specific	Based on Mid-year Gross	Transmission PP & E	
Deferred Expenses - Other	Based on Mid-year Gross	PP & E Without General F	
Working Capital (detailed above)	Based on Mid-year Gross	PP & E Without General F	
Rate Case Expense	Based on Mid-year Gross	PP & E Without General P	

Percentage of Customer Accounting Cost Allocated Based on Avg No. of Customers	98%
Percentage of Customer Accounting Cost Allocated Based on Energy Sale	2%
Percentage of Marketing Cost Allocated Based on Avg No. of Customers	15%
Percentage of Marketing Cost Allocated Based on Energy Sale	85%

NORTHLAND (Yellowknife) UTILITIES LIMITED -- 2005/06 GRA

Revenue to Cost Summary on Existing Rates

Line No.	Rate	2005 Revenue	2005 Cost	2005 Rev/Cost	2006 Revenue	2006 Cost	2006 Rev/Cost
1	Domestic	$10,287,726	$10,813,376	95%	$10,458,596	$11,082,555	94%
2	General Service	$16,581,066	$16,078,124	103%	$16,783,335	$16,476,351	102%
3	Street Light	$679,206	$610,141	111%	$685,931	$625,201	110%
4	Space Light	$15,902	$14,876	107%	$15,902	$15,240	104%
5	COMPANY TOTAL	**$27,563,899**	**$27,516,518**	**100%**	**$27,943,764**	**$28,199,346**	**99%**

NORTHLAND (Yellowknife) UTILITIES LIMITED -- 2005/06 GRA

Revenue to Cost Summary on Proposed Rates

Line No.	Rate	2005 Revenue	2005 Cost	2005 Rev/Cost	2006 Revenue	2006 Cost	2006 Rev/Cost
1	Domestic	$10,292,139	$10,820,531	95%	$10,580,463	$11,091,437	95%
2	General Service	$16,615,146	$16,090,317	103%	$17,000,894	$16,491,143	103%
3	Street Light	$612,532	$608,969	101%	$625,533	$624,112	100%
4	Space Light	$14,861	$14,861	100%	$15,028	$15,227	99%
5	COMPANY TOTAL	**$27,534,678**	**$27,534,678**	**100%**	**$28,221,918**	**$28,221,918**	**100%**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA

Comparison of Revenue (Existing vs Proposed Rates)

Line No.	Rate	2005 Existing	2005 Proposed	2005 Increase%	2006 2005 Proposed	2006 Proposed	2006 Increase%
1	Domestic	$10,287,726	$10,292,139	0.0%	$10,463,144	$10,580,463	1.1%
2	General Service	$16,581,066	$16,615,146	0.2%	$16,812,383	$17,000,894	1.1%
3	Street Light	$679,206	$612,532	-9.8%	$618,597	$625,533	1.1%
4	Space Light	$15,902	$14,861	-6.5%	$14,861	$15,028	1.1%
5	COMPANY TOTAL	**$27,563,899**	**$27,534,678**	**-0.1%**	**$27,908,985**	**$28,221,918**	**1.1%**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA

Yellowknife Residential

Monthly Bill Comparison

	Consumption (kW.h)										
	100	200	300	400	500	600	700	800	900	1000	1100
Proposed 2005 Rates	$35.11	$50.95	$66.80	$82.65	$98.49	$114.34	$130.19	$146.03	$161.88	$177.73	$193.57
Existing Rates	$33.37	$49.48	$65.60	$81.72	$97.83	$113.95	$130.06	$146.18	$162.29	$178.41	$194.52
Difference (%)	5.21%	2.97%	1.83%	1.14%	0.68%	0.35%	0.10%	-0.10%	-0.25%	-0.38%	-0.49%

Sample Bill Calculation

		Existing					Proposed 2005				
1	Customer Charge	$15.00				$15.00	$18.00				$18.00
2	Energy Charge	600	KW.h @$	0.1172		$70.32	600	KW.h @$	0.1428		$85.68
3	BASE BILL (1 + 2)					$85.32					$103.68
4	Purchased Power Adjustment (Rider P)	$85.32	x	7.501%	=	$6.40	$103.68	x	0.00%	=	$0.00
5	NET BASE RATE (3 + 4)					$91.72					$103.68
6	Snare Cascades Hydro Rider (Rider B)	600	KW.h @$	0.005313		$3.19	600	KW.h @$	0.005300		$3.18
7	NTPC Shortfall Rider (Rider C)	600	KW.h @$	0.019308		$11.58					
8	SUBTOTAL (5 + 6 + 7)					$106.49					$106.86
9	Franchise Tax	$106.49	x	0.0000%	=	0.00	$106.86	x	0.00%	=	0.00
10	Income Tax Rebate	$106.49	x	0.00%	=	0.00	$106.86	x	0.00%	=	0.00
11	NET BILL (8 + 9 + 10)					$106.49					$106.86
12	G.S.T.	$106.49	x	7.00%		$7.45	$106.86	x	7.00%		$7.48
13	**TOTAL BILL (11 + 12)**					**$113.95**					**$114.34**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA

Yellowknife General Service

Monthly Bill Comparison

Load Factor		Load (kV.a) 5	7	10	12	15	17	20	22	25	27	30
10%	Proposed 2005 Rates	$91.44	$128.01	$182.87	$219.45	$274.31	$310.88	$365.75	$402.32	$457.18	$493.76	$548.62
	Existing Rates	$97.63	$136.68	$195.25	$234.31	$292.88	$331.93	$390.51	$429.56	$488.14	$527.19	$585.76
	Difference (%)	-6.34%	-6.34%	-6.34%	-6.34%	-6.34%	-6.34%	-6.34%	-6.34%	-6.34%	-6.34%	-6.34%
20%	Proposed 2005 Rates	$143.50	$200.90	$286.99	$344.39	$430.49	$487.89	$573.99	$631.39	$717.48	$774.88	$860.98
	Existing Rates	$148.09	$207.33	$296.19	$355.43	$444.28	$503.52	$592.38	$651.61	$740.47	$799.71	$888.56
	Difference (%)	-3.10%	-3.10%	-3.10%	-3.10%	-3.10%	-3.10%	-3.10%	-3.10%	-3.10%	-3.10%	-3.10%
30%	Proposed 2005 Rates	$195.56	$273.78	$391.11	$469.34	$586.67	$664.89	$782.23	$860.45	$977.78	$1,056.01	$1,173.34
	Existing Rates	$198.56	$277.98	$397.12	$476.55	$595.68	$675.11	$794.24	$873.67	$992.80	$1,072.23	$1,191.36
	Difference (%)	-1.51%	-1.51%	-1.51%	-1.51%	-1.51%	-1.51%	-1.51%	-1.51%	-1.51%	-1.51%	-1.51%
40%	Proposed 2005 Rates	$247.62	$346.66	$495.23	$594.28	$742.85	$841.90	$990.47	$1,089.52	$1,238.09	$1,337.13	$1,485.70
	Existing Rates	$249.03	$348.64	$498.05	$597.67	$747.08	$846.69	$996.11	$1,095.72	$1,245.14	$1,344.75	$1,494.16
	Difference (%)	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%
50%	Proposed 2005 Rates	$299.68	$419.55	$599.36	$719.23	$899.03	$1,018.90	$1,198.71	$1,318.58	$1,498.39	$1,618.26	$1,798.07
	Existing Rates	$299.49	$419.29	$598.99	$718.79	$898.48	$1,018.28	$1,197.98	$1,317.77	$1,497.47	$1,617.27	$1,796.96
	Difference (%)	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%

40%

Sample Bill Calculation

		Existing					Proposed 2005				
1	Demand Charge	5	kV.a @$	8.20		$41.00	5	kV.a @$	7.36		$36.80
2	Energy Charge	1,460	KW.h @$	0.0973		142.06	1,460	KW.h @$	0.1280		186.88
3	BASE BILL (1 + 2)					$183.06					$223.68
4	Purchased Power Adjustment (Rider P)	$183.06	x	7.501%	=	13.73	$223.68	x	0.00%	=	0.00
5	NET BASE RATE (3 + 4)					$196.79					$223.68
6	Snare Cascades Hydro Rider (Rider B)	1,460	KW.h @$	0.005313		$7.76	1,460	KW.h @$	0.005300		$7.74
7	NTPC Shortfall Rider (Rider C)	1,460	KW.h @$	0.019308		$28.19	1,460	KW.h @$	0		$0.00
8	SUBTOTAL (5 + 6 + 7)					$232.74					$231.42
9	Franchise Tax	$232.74	x	0.00%	=	0.00	$231.42	x	0.00%	=	0.00
10	Income Tax Rebate	$232.74	x	0.00%	=	0.00	$231.42	x	0.00%	=	0.00
11	NET BILL					$232.74					$231.42
12	G.S.T.	$232.74	x	7.00%		$16.29	$231.42	x	7.00%		$16.20
13	***TOTAL BILL***					**$249.03**					**$247.62**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA

Yellowknife Street Lights

	Bulb Wattage (Watts)								
	M.V.	M.V.	M.V.	H.P.S.	H.P.S.	H.P.S.	H.P.S.	H.P.S.	H.P.S.
Monthly Bill Comparison	175	250	400	50	70	100	150	250	400
Proposed 2005 Rates	$26.61	$38.65	$45.84	$6.45	$9.04	$12.89	$34.79	$39.60	$46.50
Existing Rates	$29.53	$42.90	$50.83	$7.16	$10.03	$14.31	$38.59	$43.93	$51.57
Difference (%)	-9.89%	-9.91%	-9.82%	-9.92%	-9.87%	-9.92%	-9.85%	-9.86%	-9.83%

Sample Bill Calculation

		Existing					Proposed 2005				
2	Charge per Light	400	Watts HPS	$41.29		41.29	400	Watts HPS	$42.64		42.64
3	BASE BILL					$41.29					$42.64
4	Purchased Power Adjustment (Rider P)	$41.29	x	7.501%	=	3.10	$42.64	x	0.00%	=	0.00
5	NET BASE RATE					$44.39					$42.64
6	Snare Cascades Hydro Rider (Rider B)	155	KW.h @$	0.005313		$0.82	155	KW.h @$	0.005300		$0.82
7	NTPC Shortfall Rider (Rider C)	155	KW.h @$	0.019308		$2.99					
8	SUBTOTAL (5 + 6 + 7)					$48.20					$43.46
6	Franchise Tax	$48.20	x	0.00%	=	0.00	$43.46	x	0.00%	=	0.00
7	Income Tax Rebate	$48.20	x	0.00%	=	0.00	$43.46	x	0.00%	=	0.00
8	NET BILL					$48.20					$43.46
9	G.S.T.	$48.20	x	7.00%		$3.37	$43.46	x	7.00%		$3.04
10	***TOTAL BILL***					**$51.57**					**$46.50**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA

Yellowknife Space Lights

Monthly Bill Comparison	M.V. 175	M.V. 250	M.V. 400	H.P.S. 150	H.P.S. 250	H.P.S. 400
	Bulb Wattage (Watts)					
Proposed 2005 Rates	$14.26	$20.67	$24.97	$18.31	$21.23	$25.33
Existing Rates	$15.27	$22.14	$26.72	$19.61	$22.73	$27.10
Difference (%)	-6.59%	-6.62%	-6.53%	-6.66%	-6.59%	-6.55%

Sample Bill Calculation

		Existing					Proposed 2005				
2	Demand Charge	150	Watts HPS	$15.54		15.54	150	Watts	$16.76		16.76
3	BASE BILL					$15.54					$16.76
4	Purchased Power Adjustment (Rider P)	$15.54	x	7.501%	=	1.17	$16.76	x	0.00%	=	0.00
5	NET BASE RATE					$16.71					$16.76
6	Snare Cascades Hydro Rider (Rider B)	66	KW.h @$	0.005313		$0.35	66	KW.h @$	0.005300		$0.35
7	NTPC Shortfall Rider (Rider C)	66	KW.h @$	0.019308		$1.27					
8	SUBTOTAL (5 + 6 + 7)					$18.33					$17.11
6	Franchise Tax	$18.33	x	0.00%	=	0.00	$17.11	x	0.00%	=	0.00
7	Income Tax Rebate	$18.33	x	0.00%	=	0.00	$17.11	x	0.00%	=	0.00
8	NET BILL					$18.33					$17.11
9	G.S.T.	$18.33	x	7.00%		$1.28	$17.11	x	7.00%		$1.20
10	***TOTAL BILL***					**$19.61**					**$18.31**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA

Summary of 2005 Rider A

		Domestic	General Service	Street Lights	Space Lights	Total
1	Total 2005 Revenue (Existing and Proposed Rates)	10,295,630	16,591,723	645,741	15,382	27,548,476
2	Total 2005 Revenue (Proposed 2005 Rates)	10,292,139	16,615,146	612,532	14,861	27,534,678
3	Total Revenue Difference (a)	(3,491)	23,422	(33,208)	(520)	(13,797)
4	Rider S: NWTPC Shortfall Rider Balance	4,141	7,321	109	5	11,577
5	Income Tax Rebate Balance	(3,712)	(6,563)	(98)	(5)	(10,378)
6	Total to be collected / refunded	(3,062)	24,181	(33,197)	(520)	(12,598)
7	Total Proposed Base Revenue (Proposed 2005 Rates)					
8	July 1st to December 31st	4,702,934	7,967,341	299,890	7,248	12,977,413
9	Proposed Rider A for Customer Class	-0.065%	0.303%	-11.070%	-7.170%	
10	Total Rider A Revenue (b)	(3,062)	24,181	(33,197)	(520)	(12,598)
11	Difference (shortfall/surplus) a - b =	0	(0)	0	0	(0)

Residential Rate Class

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	TOTAL
Total Domestic Revenue (Existing Rates & Riders)													
Customer ($)	96,615	96,570	96,540	96,630	96,735	96,870	0	0	0	0	0	0	**579,960**
Demand ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Block 1 Energy ($)	790,582	647,184	673,924	557,696	514,403	489,150	0	0	0	0	0	0	**3,672,940**
Block 2 Energy ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total Adjustments	260,031	214,636	223,097	186,317	172,624	164,644	0	0	0	0	0	0	**1,221,349**
Total	1,147,228	958,391	993,561	840,643	783,762	750,664	0	0	0	0	0	0	**5,474,249**
Total Domestic Revenue (Proposed 2005 Rates & Riders)													
Customer ($)	115,938	115,884	115,848	115,956	116,082	116,244	0	0	0	0	0	0	**695,952**
Demand ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Block 1 Energy ($)	963,073	788,388	820,962	679,375	626,636	595,873	0	0	0	0	0	0	**4,474,307**
Block 2 Energy ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total Adjustments	63,828	52,779	54,838	45,886	42,554	40,613	0	0	0	0	0	0	**300,498**
Total	1,142,839	957,051	991,648	841,218	785,272	752,730	0	0	0	0	0	0	**5,470,757**
Revenue Shortfall	-4,389	-1,340	-1,913	575	1,510	2,066	0	0	0	0	0	0	**-3,491**
Total													

Rider S: NWTPC Shortfall Rider Allocated Balance	**4,141**
Income Tax Rebate Allocated Balance	**(3,712)**
Total Revenue Shortfall to be Recovered	***-3,062***
Proposed Base Revenue (July 1 2005 to December 31 2005)	
Total	***4,702,934***
Residential Rate Class Rider A Surcharge	***-0.065%*** **(July 1, 2005 to December 31, 2005)**

Commercial Rate Class

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	TOTAL
Total General Service Revenue (Existing Rates & Riders)													
Customer ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Demand ($)	222,589	222,409	218,809	216,874	215,816	220,982	0	0	0	0	0	0	**1,317,478**
Block 1 Energy ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Block 2 Energy ($)	1,017,552	792,579	965,763	823,078	776,912	749,091	0	0	0	0	0	0	**5,124,976**
Total Adjustments	389,425	308,294	370,370	318,729	301,977	292,470	0	0	0	0	0	0	**1,981,264**
Total	1,629,566	1,323,282	1,554,941	1,358,681	1,294,705	1,262,543	0	0	0	0	0	0	**8,423,717**
Total General Service Revenue (Proposed 2005 Rates & Riders)													
Customer ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Demand ($)	205,618	205,459	202,226	200,485	199,539	204,172	0	0	0	0	0	0	**1,217,500**
Block 1 Energy ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Block 2 Energy ($)	1,338,798	1,042,800	1,270,659	1,082,928	1,022,187	985,583	0	0	0	0	0	0	**6,742,956**
Rider B Adjustment	95,720	75,698	91,027	78,287	74,155	71,796	0	0	0	0	0	0	**486,684**
Total	1,640,137	1,323,958	1,563,912	1,361,700	1,295,881	1,261,552	0	0	0	0	0	0	**8,447,140**
Revenue Surplus	10,571	677	8,971	3,019	1,176	(991)	0	0	0	0	0	0	**23,422**
Total													

Rider S: NWTPC Shortfall Rider Allocated Balance	**7,321**
Income Tax Rebate Allocated Balance	**(6,563)**
Total Revenue Surplus to be Reimbursed	***24,181***
Proposed Base Revenue (July 1 2005 to December 31 2005)	
Total	***7,967,341***
Commercial Rate Class Rider A Surcharge	***0.303%*** **(July 1, 2005 to December 31, 2005)**

Street Light Rate Class

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	TOTAL
Total Street Light Revenue (Existing Rates & Riders)													
Customer ($)	48,076	48,140	48,240	48,304	48,368	48,468	0	0	0	0	0	0	**289,598**
Demand ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Block 1 Energy ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Block 2 Energy ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total Adjustments	8,087	8,096	8,113	8,122	8,132	8,148	0	0	0	0	0	0	**48,699**
Total	56,163	56,237	56,353	56,427	56,501	56,617	0	0	0	0	0	0	**338,297**
Total Street Light Revenue (Proposed 2005 Rates & Riders)													
Customer ($)	48,730	48,794	48,895	48,959	49,024	49,124	0	0	0	0	0	0	**293,526**
Demand ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Block 1 Energy ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Block 2 Energy ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Rider B Adjustment	1,920	1,922	1,926	1,929	1,931	1,935	0	0	0	0	0	0	**11,563**
Total	50,650	50,717	50,821	50,888	50,954	51,059	0	0	0	0	0	0	**305,089**
Revenue Shortfall (Existing Rates)	(5,513)	(5,520)	(5,532)	(5,539)	(5,546)	(5,558)	0	0	0	0	0	0	**(33,208)**
Total													

Rider S: NWTPC Shortfall Rider Allocated Balance	**109**
Income Tax Rebate Allocated Balance	**(98)**
Total Revenue Shortfall to be Recovered	***(33,197)***

Proposed Base Revenue (July 1 2005 to December 31 2005)
Total ***299,890***

Street Lights Rate Class Rider A Surcharge ***-11.070%*** **(July 1, 2005 to December 31, 2005)**

Space Light Rate Class

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	TOTAL
Total Space Light Revenue (Existing Rates & Riders)													
Customer ($)	1,062	1,062	1,062	1,062	1,062	1,062	0	0	0	0	0	0	**6,371**
Demand ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Block 1 Energy ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Block 2 Energy ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total Adjustments	263	263	263	263	263	263	0	0	0	0	0	0	**1,580**
Total	1,325	1,325	1,325	1,325	1,325	1,325	0	0	0	0	0	0	**7,951**
Total Space Light Revenue (Proposed 2005 Rates & Riders)													
Customer ($)	1,175	1,175	1,175	1,175	1,175	1,175	0	0	0	0	0	0	**7,052**
Demand ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Block 1 Energy ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Block 2 Energy ($)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Rider B Adjustment	63	63	63	63	63	63	0	0	0	0	0	0	**379**
Total	1,238	1,238	1,238	1,238	1,238	1,238	0	0	0	0	0	0	**7,431**
Revenue Surplus (Existing Rates)	(87)	(87)	(87)	(87)	(87)	(87)	0	0	0	0	0	0	**(520)**
Total													
Rider S: NWTPC Shortfall Rider Allocated Balance	**5**												
Income Tax Rebate Allocated Balance	**(5)**												
Total Revenue Surplus to be Reimbursed	*(520)*												
Proposed Base Revenue (July 1 2005 to December 31 2005)													
Total	*7,248*												
Street Lights Rate Class Rider A Surcharge	*-7.170%*	**(July 1, 2005 to December 31, 2005)**											

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Domestic

	2005					2006				
Billing Determinants	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**
Yellowknife Domestic	77,647		58,361,540		58,361,540	78,965		59,327,834		59,327,834

	2005				2006			
Proposed Rate	Customer Charge ($/cust)	Demand Charge ($ / kW)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Customer Charge ($/cust)	Demand Charge ($ / kW)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)
Yellowknife Domestic	18.00		14.28		18.00		14.28	

	2005					2006				
Proposed Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**
Yellowknife Domestic	1,397,646		8,332,327		**9,729,973**	1,421,370		8,470,286		**9,891,656**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife General Service

Billing Determinants	2005 Number of Customers Billed/year	2005 Demand kV.a	2005 Block 1 Energy (kW.h)	2005 Block 2 Energy (kW.h)	2005 Total Energy (kW.h)	2006 Number of Customers Billed/year	2006 Demand kW	2006 Block 1 Energy (kW.h)	2006 Block 2 Energy (kW.h)	2006 Total Energy (kW.h)
Yellowknife General Service	12,602	333,161	103,173,463		103,173,463	12,672	340,833	104,193,035		104,193,035

Proposed Rate	2005 Customer Charge ($/cust)	2005 Demand Charge ($ / kV.a)	2005 Block 1 Energy Chg (¢ / kW.h)	2005 Block 2 Energy Chg (¢ / kW.h)	2006 Customer Charge ($/cust)	2006 Demand Charge ($ / kW)	2006 Block 1 Energy Chg (¢ / kW.h)	2006 Block 2 Energy Chg (¢ / kW.h)
Yellowknife General Service		7.36	12.80			7.36	12.80	

Proposed Revenue ($)	2005 Customer Revenue	2005 Demand Revenue	2005 Block 1 Energy Revenue	2005 Block 2 Energy Revenue	2005 Total Rate Revenue	2006 Customer Revenue	2006 Demand Revenue	2006 Block 1 Energy Revenue	2006 Block 2 Energy Revenue	2006 Fuel Charge Revenue	2006 Total Rate Revenue
Yellowknife General Service		2,452,068	13,208,070		**15,660,138**		2,508,532	13,338,594		0	**15,847,126**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Street Lights

	2005					2006				
Billing Determinants	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**
250W MV	396				0.00	396				0

	2005				2006				
Proposed Rate	Customer Charge ($/cust)	Demand Charge ($ / kW)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Customer Charge ($/cust)	Demand Charge ($ / kW)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Fuel Charge (¢ / kW.h)
250W MV	35.60				35.60				

	2005					2006					
Proposed Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Fuel Charge Revenue	**Total Rate Revenue**
250W MV	14,099				**14,099**	14,099		0		0	**14,099**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Street Lights

	2005					2006				
Billing Determinants	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**
400W MV	624					624				

	2005				2006			
Proposed Rate	Customer Charge ($/cust)	Demand Charge ($ / kW)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Customer Charge ($/cust)	Demand Charge ($ / kW)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)
400W MV	42.03				42.03			

	2005						2006					
Proposed Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Fuel Charge Revenue	**Total Rate Revenue**	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	Fuel Charge Revenue	**Total Rate Revenue**
400W MV	26,225		0		0	**26,225**	26,225		0		0	**26,225**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Street Lights

	2005					2006				
Billing Determinants	**Number of Lamps Billed/year**	**Demand Watts**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**	**Number of Lamps Billed/year**	**Demand Watts**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**
50 W HPS	144					144				

Proposed Rate	Customer Charge ($/lamp)	Demand Charge (¢ / Watt)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Customer Charge ($/lamp)	Demand Charge (¢ / Watt)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)
50 W HPS	5.93				5.93			

Proposed Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**
50 W HPS	854				**854**	854				**854**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Street Lights

	2005					2006				
Billing Determinants	**Number of Lamps Billed/year**	**Demand Watts**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**	**Number of Lamps Billed/year**	**Demand Watts**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**
70 W HPS	24					24				

Proposed Rate	Customer Charge ($/lamp)	Demand Charge (¢ / Watt)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Customer Charge ($/lamp)	Demand Charge (¢ / Watt)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)
70 W HPS	8.31				8.31			

Proposed Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**
70 W HPS	199				**199**	199				**199**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Street Lights

Billing Determinants	2005 Number of Lamps Billed/year	2005 Demand Watts	2005 Block 1 Energy (kW.h)	2005 Block 2 Energy (kW.h)	2005 Total Energy (kW.h)	2006 Number of Lamps Billed/year	2006 Demand Watts	2006 Block 1 Energy (kW.h)	2006 Block 2 Energy (kW.h)	2006 Total Energy (kW.h)
100 W HPS	24					24				

Proposed Rate	2005 Customer Charge ($/lamp)	2005 Demand Charge (¢ / Watt)	2005 Block 1 Energy Chg (¢ / kW.h)	2005 Block 2 Energy Chg (¢ / kW.h)	2006 Customer Charge ($/lamp)	2006 Demand Charge (¢ / Watt)	2006 Block 1 Energy Chg (¢ / kW.h)	2006 Block 2 Energy Chg (¢ / kW.h)
100 W HPS	11.85				11.85			

Proposed Revenue ($)	2005 Customer Revenue	2005 Demand Revenue	2005 Block 1 Energy Revenue	2005 Block 2 Energy Revenue	2005 Total Rate Revenue	2006 Customer Revenue	2006 Demand Revenue	2006 Block 1 Energy Revenue	2006 Block 2 Energy Revenue	2006 Total Rate Revenue
100 W HPS	285				**285**	285				**285**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Street Lights

Billing Determinants	2005 Number of Customers Billed/year	2005 Demand kW	2005 Block 1 Energy (kW.h)	2005 Block 2 Energy (kW.h)	2005 Total Energy (kW.h)	2006 Number of Customers Billed/year	2006 Demand kW	2006 Block 1 Energy (kW.h)	2006 Block 2 Energy (kW.h)	2006 Total Energy (kW.h)
150W HPS	6,643				0	6,784				0

Proposed Rate	2005 Customer Charge ($/cust)	2005 Demand Charge ($ / kW)	2005 Block 1 Energy Chg (¢ / kW.h)	2005 Block 2 Energy Chg (¢ / kW.h)	2006 Customer Charge ($/cust)	2006 Demand Charge ($ / kW)	2006 Block 1 Energy Chg (¢ / kW.h)	2006 Block 2 Energy Chg (¢ / kW.h)
150W HPS	32.16				32.16			

Proposed Revenue ($)	2005 Customer Revenue	2005 Demand Revenue	2005 Block 1 Energy Revenue	2005 Block 2 Energy Revenue	2005 Total Rate Revenue	2006 Customer Revenue	2006 Demand Revenue	2006 Block 1 Energy Revenue	2006 Block 2 Energy Revenue	2006 Total Rate Revenue
150W HPS	213,606				**213,606**	218,140				**218,140**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Street Lights

Billing Determinants	2005 Number of Customers Billed/year	2005 Demand kW	2005 Block 1 Energy (kW.h)	2005 Block 2 Energy (kW.h)	2005 Total Energy (kW.h)	2006 Number of Customers Billed/year	2006 Demand kW	2006 Block 1 Energy (kW.h)	2006 Block 2 Energy (kW.h)	2006 Total Energy (kW.h)
250W HPS	9,118				0	9,154				0

Proposed Rate	2005 Customer Charge ($/cust)	2005 Demand Charge ($ / kW)	2005 Block 1 Energy Chg (¢ / kW.h)	2005 Block 2 Energy Chg (¢ / kW.h)	2006 Customer Charge ($/cust)	2006 Demand Charge ($ / kW)	2006 Block 1 Energy Chg (¢ / kW.h)	2006 Block 2 Energy Chg (¢ / kW.h)
250W HPS	36.45				36.45			

Proposed Revenue ($)	2005 Customer Revenue	2005 Demand Revenue	2005 Block 1 Energy Revenue	2005 Block 2 Energy Revenue	2005 Total Rate Revenue	2006 Customer Revenue	2006 Demand Revenue	2006 Block 1 Energy Revenue	2006 Block 2 Energy Revenue	2006 Total Rate Revenue
250W HPS	332,367				**332,367**	333,679				**333,679**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Street Lights

	2005					2006				
Billing Determinants	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**
400W HPS	12				0	12				0

Proposed Rate	Customer Charge ($/cust)	Demand Charge ($ / kW)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Customer Charge ($/cust)	Demand Charge ($ / kW)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)
400W HPS	42.64				42.64			

Proposed Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**
400W HPS	512				**512**	512				**512**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Street Lights

	2005					2006				
Billing Determinants	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**
175W MV	48				0	48				0

Proposed Rate	Customer Charge ($/cust)	Demand Charge ($ / kW)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Customer Charge ($/cust)	Demand Charge ($ / kW)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)
175W MV	24.50				24.50			

Proposed Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**
175W MV	1,176				**1,176**	1,176				**1,176**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Space Lights

Billing Determinants	2005 Number of Customers Billed/year	2005 Demand kW	2005 Block 1 Energy (kW.h)	2005 Block 2 Energy (kW.h)	2005 Total Energy (kW.h)	2006 Number of Customers Billed/year	2006 Demand kW	2006 Block 1 Energy (kW.h)	2006 Block 2 Energy (kW.h)	2006 Total Energy (kW.h)
175 W MV	0				0	0				0

Proposed Rate	2005 Customer Charge ($/cust)	2005 Demand Charge ($ / kW)	2005 Block 1 Energy Chg (¢ / kW.h)	2005 Block 2 Energy Chg (¢ / kW.h)	2005 Fuel Charge (¢ / kW.h)	2006 Customer Charge ($/cust)	2006 Demand Charge ($ / kW)	2006 Block 1 Energy Chg (¢ / kW.h)	2006 Block 2 Energy Chg (¢ / kW.h)
175 W MV	12.96					12.96			

Proposed Revenue ($)	2005 Customer Revenue	2005 Demand Revenue	2005 Block 1 Energy Revenue	2005 Block 2 Energy Revenue	2005 Total Rate Revenue	2006 Customer Revenue	2006 Demand Revenue	2006 Block 1 Energy Revenue	2006 Block 2 Energy Revenue	2006 Total Rate Revenue
175 W MV	0				**0**	0				**0**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Space Lights

	2005					2006				
Billing Determinants	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**	**Number of Customers Billed/year**	**Demand kW**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**
250 W MV	0				0	0				0

	2005					2006			
Proposed Rate	Customer Charge ($/cust)	Demand Charge ($ / kW)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Fuel Charge (¢ / kW.h)	Customer Charge ($/cust)	Demand Charge ($ / kW)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)
250 W MV	18.80					18.80			

	2005					2006				
Proposed Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**
250 W MV	0				**0**	0				**0**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Space Lights

	2005					2006				
Billing Determinants	**Number of Lamps Billed/year**	**Demand Watts**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**	**Number of Lamps Billed/year**	**Demand Watts**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**
400 W MV	108					108				

Proposed Rate	Customer Charge ($/lamp)	Demand Charge (¢ / Watt)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Customer Charge ($/lamp)	Demand Charge (¢ / Watt)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)
400 W MV	22.53				22.53			

Proposed Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**
400 W MV	2,433				**2,433**	2,433				**2,433**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Street Lights

	2005					2006				
Billing Determinants	**Number of Lamps Billed/year**	**Demand Watts**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**	**Number of Lamps Billed/year**	**Demand Watts**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**
150 W HPS	252					252				

	2005				2006			
Proposed Rate	Customer Charge ($/lamp)	Demand Charge (¢ / Watt)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Customer Charge ($/lamp)	Demand Charge (¢ / Watt)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)
150 W HPS	16.76				16.76			

	2005					2006				
Proposed Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**
150 W HPS	4,225				**4,225**	4,225				**4,225**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Space Lights

	2005					2006				
Billing Determinants	**Number of Lamps Billed/year**	**Demand Watts**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**	**Number of Lamps Billed/year**	**Demand Watts**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**
250W HPS	372					372				

Proposed Rate	Customer Charge ($/lamp)	Demand Charge (¢ / Watt)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Customer Charge ($/lamp)	Demand Charge (¢ / Watt)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)
250W HPS	19.28				19.28			

Proposed Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**
250W HPS	7,171				**7,171**	7,171				**7,171**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

Yellowknife Space Lights

	2005					2006				
Billing Determinants	**Number of Lamps Billed/year**	**Demand Watts**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**	**Number of Lamps Billed/year**	**Demand Watts**	Block 1 Energy (kW.h)	Block 2 Energy (kW.h)	**Total Energy (kW.h)**
400W HPS	12					12				

Proposed Rate	Customer Charge ($/lamp)	Demand Charge (¢ / Watt)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)	Customer Charge ($/lamp)	Demand Charge (¢ / Watt)	Block 1 Energy Chg (¢ / kW.h)	Block 2 Energy Chg (¢ / kW.h)
400W HPS	22.85				22.85			

Proposed Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**
400W HPS	274				**274**	274				**274**

NORTHLAND UTILITIES (Yellowknife) LIMITED -- 2005/06 GRA
Schedule of Determinants

TOTAL RATE REVENUE

	2005					2006				
Proposed Revenue ($)	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**	Customer Revenue	Demand Revenue	Block 1 Energy Revenue	Block 2 Energy Revenue	**Total Rate Revenue**
Base Rates	2,001,072	2,452,068	21,540,397	0	**25,993,537**	2,030,642	2,508,532	21,808,880	0	**26,348,054**
Rider B					**864,690**					**875,285**
Rider R (Note 1)										**308,637**
Franchise Taxes					**676,451**					**689,943**
Total Rate Revenue	**2,001,072**	**2,452,068**	**21,540,397**	**0**	**27,534,678**	**2,030,642**	**2,508,532**	**21,808,880**	**0**	**28,221,918**

Note 1: Rider R = 1.13%

Northland Utilities (Yellowknife) Limited
Determination of 2005 Franchise Tax Rate
($000's)

Line No.		
1	**Forecast base revenue for the period January 1 to December 31, 2005**	26,858
2	**Forecast revenue from Joint-Use**	138
3	**Total Forecast Gross Revenue**	26,996
4	**Forecast Franchise Tax Liability for 2005**	
5	First $5,250 @ 4%	210
6	Next $3,500@ 3%	105
7	Balance @ 2%	365
8	**Total Forecast Franchise Tax Liability for 2005**	680
9	**Franchise Tax Rate (Line 8/Line 3)**	2.5186%
10	Forecast over-collection to December 31, 2004 per Schedule 2	(14)
11	**Franchise Tax Rate adjustment for over-collection(Line 10/Line 3)**	-0.0530%
12	**Net Franchise Tax Rate (Line 9 + Line 11)**	2.4656%
13	**Net Forecast Franchise Taxes to be collected from customers**	666

Northland Utilities (Yellowknife) Limited
Determination of the Snare Cascades Hydro Rider (Rider B) Rate
($000's)

Line No.				$ per kWh
1	**NTPC Snare Cascades Hydro Rider**	0.005	$ per kWh	
2	**Proposed line loss factor**	1.06		
3	**Rider B Rate**			0.005300
4	**Forecast Energy Sales**	163,149,094	kW.h	
5	**Forecast Over-Collection as of December 31, 2004**	($14,672.76)		
6	**Over-Collection Portion**			-0.000090
7	**Total Rider B Rate**			0.005210

Section 13 – Rate Schedules

A. Overview

This section contains Northland's proposed 2005 Rate Schedules, and the retained Rider Schedules.

RATE SCHEDULE INDEX

DOMESTIC RATE SCHEDULE

Application

- For single-phase service at secondary voltage through a single meter.
- For normal use by a single and separate household.
- Not applicable to any commercial or industrial use.
- As requested by the City of Yellowknife, churches assessed as exempt will be entitled to this rate.

Rates

- The charge for service in any one billing month is the sum of the Customer Charge and Energy Charge, determined for each individual Point of Service.

Component	Charge
Customer Charge	\$18.00 / month
Energy Charge	14.28 ¢ / kW.h

- The minimum monthly charge is the Customer Charge.

Options and Riders

Price Adjustments – the following price adjustments (riders) may apply:
Temporary Refund/Surcharge Rider (Rider A)
Snare Cascades Hydro Rider (Rider B)
NTPC GRA Shortfall Adjustment Rider (Rider C)
Purchase Power Adjustment Rider (Rider P)
Franchise Tax

GENERAL SERVICE (COMMERCIAL) RATE SCHEDULE

Application

- To any use of electric energy consistent with safe and adequate service to all customers of the Company.
- For single-or three-phase service at secondary voltage through a single meter.

Rates

- The charge for service in any one billing month is the sum of the Demand Charge and Energy Charge, determined for each individual Point of Service.

Component	**Charge**
Demand Charge	$ 7.36 / kV.a / month
Energy Charge	12.80 ¢ / kW.h

- The billing demand may be estimated or measured and will be the greater of the following:
  (a) The highest metered demand during the billing period;
  (b) 75% of the highest demand set in the twelve (12) month period including and ending with the billing period;
  (c) the estimated demand;
  (d) 5 kV.a

Options and Riders

Price Adjustments – the following price adjustments (riders) may apply:
Temporary Refund/Surcharge Rider (Rider A)
Snare Cascades Hydro Rider (Rider B)
NTPC GRA Shortfall Adjustment Rider (Rider C)
Purchase Power Adjustment Rider (Rider P)
Franchise Tax

STREET LIGHT RATE SCHEDULE

Application

- For all Points of Service throughout the City of Yellowknife that are served by the Company, for street lighting.
- Applies to all standard mercury vapour and high pressure sodium street lights.

Rates

- The charge for service in any one billing month is the light charge for each individual Point of Service.

Type	Component	Monthly Charge per Light
Mercury Vapour	175 Watt	$ 24.50
	250 Watt	$ 35.60
	400 Watt	$ 42.03
High Pressure Sodium	50 Watt	$ 5.93
	70 Watt	$ 8.31
	100 Watt	$ 11.85
	150 Watt	$ 32.16
	250 Watt	$ 36.45
	400 Watt	$ 42.64

Options and Riders

Price Adjustments – the following price adjustments (riders) may apply:

Temporary Refund/Surcharge Rider (Rider A)
Snare Cascades Hydro Rider (Rider B)
NTPC GRA Shortfall Adjustment Rider (Rider C)
Purchase Power Adjustment Rider (Rider P)
Franchise Tax

SPACE LIGHT RATE SCHEDULE

Application

- For all Points of Service throughout the City of Yellowknife that are served by the Company, for space lighting.
- Applies to all standard mercury vapour and high pressure sodium street lights.

Rates

- The charge for service in any one billing month is the light charge for each individual Point of Service.

Type	Component	Monthly Charge per Light
Mercury Vapour	175 Watt	$ 12.96
	250 Watt	$ 18.80
	400 Watt	$ 22.53
High Pressure Sodium	150 Watt	$ 16.76
	250 Watt	$ 19.28
	400 Watt	$ 22.85

Options and Riders

Price Adjustments – the following price adjustments (riders) may apply:

Temporary Refund/Surcharge Rider (Rider A)
Snare Cascades Hydro Rider (Rider B)
NTPC GRA Shortfall Adjustment Rider (Rider C)
Purchase Power Adjustment Rider (Rider P)
Franchise Tax

TEMPORARY REFUND / SURCHARGE RIDER (Rider A)

SAMPLE

Applicable

- Rider A is applicable to all rate classes defined by the Company for services provided in the City of Yellowknife

Rates

- The charges listed below are in effect over 6 months commencing July 1, 2005 and ending December 31, 2005

- A positive value indicates a surcharge and a negative value indicates a refund.

Rate Schedule	Effective Date	Expiry Date	Rate
Domestic	July 1, 2005	January 1, 2006	-0.065%
General Service	July 1, 2005	January 1, 2006	0.303%
Street Lights	July 1, 2005	January 1, 2006	-11.070%
Space Lights	July 1, 2005	January 1, 2006	-7.170%

Snare Cascades Hydro Rider (Rider B)

Applicable

- Rider B is applicable to all rate classes defined by the Company for services provided in the City of Yellowknife

Rates

- A surcharge of $0.005210 / kW.h will be applied to all energy consumption.
- Rider B is in place for a period of ten (10) years commencing May 1, 2001.

NTPC GRA Shortfall Rider (Rider C)

Applicable

- Rider C is applicable to all rate classes defined by the Company for services provided in the City of Yellowknife when a charge or refund is approved by the Board.

Rates

- A refund of $0.0 / kW.h will be applied to all energy consumption to reimburse a net over-collection.

Franchise Tax

Applicable

- The Franchise Tax is applicable to all rate classes defined by the Company for services provided in the City of Yellowknife

Rates

- Revenues billed under any of the Company's Rate Schedules are subject to a charge of 2.4656% for franchise taxes.

Purchase Power Adjustment Rider (Rider P)

Applicable

- Rider P is applicable to all rate classes defined by the Company for services provided in the City of Yellowknife when a charge or refund is approved by the Board.

Rates

- All of the company's base rate revenue will be adjusted by 0.0%.

Northland Utilities (NWT) Decision 9-2006

THE PUBLIC UTILITIES BOARD

OF THE

NORTHWEST TERRITORIES

DECISION 9-2006 **March 31, 2006**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northland Utilities (NWT) Limited for changes in the existing rates, tolls and charges for electrical energy and related services provided by Northland Utilities (NWT) Limited to their customers within the Northwest Territories.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS	John E. Hill	Chairman
	Joe Acorn	Vice-Chairman
	Gene Nikiforuk	Member
BOARD STAFF	Louise Larocque	Board Secretary
	Raj Retnanandan	Board Consultant
	John Donihee	Board Counsel

APPEARANCES

Loyola Keough	Counsel for Northland Utilities (NWT) Limited
Thomas Marriott	Counsel for The Town of Hay River
Rangi Jeerakathil	Counsel for The Hamlet of Fort Providence

WITNESSES

Northland Utilities (NWT) Limited

Dennis DeChamplain	Vice President, Controller
Doug Tenney	General Manager
Duane Morgan	Operations Manager
Bob Clarke	Senior Engineer
Ken Koenig	Senior Regulatory Analyst

Hamlet of Fort Providence

Azad Merani	Consultant to the Hamlet
Albert Lafferty	Senior Administrative Officer

Town of Hay River

Robert Bruggeman	Consultant to the Town

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1. INTRODUCTION and APPLICATION

By letter dated July 4, 2005, Northland Utilities (NWT) Limited ("**Northland**", "**Company**") submitted to the Northwest Territories Public Utilities Board ("**the Board**") a Phase I General Rate Application ("**GRA**", "**Application**") for the 2005/2006 test period ("**Test Years**") (Exhibit. 2).

In its Application, Northland requested that the Board determine Northland's revenue requirement for each of the forecast Test Years.

By letter dated August 2, 2005, Northland submitted to the Board an additional filing respecting Northland's GRA including a Phase II filing, an amended Phase I filing and a request for 2005 interim rates (Ex. 3).

In the additional filing of the Application, Northland requested that the Board:

a) Approve rate schedules;
b) Approve the revised Terms and Conditions of Service; and
c) Approve the proposed 2005 rates on an interim refundable basis

Pursuant to the provisions of section 13.(1) of the Rules of Practice and Procedure, the Board, by letters dated July 6, 2005 and August 8, 2005 directed Northland to publish notice of the public hearing of the GRA in newspapers that circulate in the Northwest Territories. The notice provided details of the GRA and invited interested persons to file a request with the Board for intervenor status (Ex. 1).

The Town of Hay River ("**Town**"), the Hamlet of Fort Providence ("**Hamlet**") the Northwest Territories Power Corporation (**"NWTPC"**) and the Community Government of Wekweeti registered their respective interventions with the Board.

The Board issued Decision 13-2005, dated September 9, 2005 with respect to Northland's proposed 2005 rates on an interim refundable basis. The Board directed Northland to file proposed interim rates for each of the communities designed to recover 50% of the proposed 2005 revenue increases, if applied on an annualized basis, for each community and to file a Rider E for each of the communities for recovery of the deficiency resulting from implementation for the interim rates effective October 1, 2005 as opposed to the beginning of the Test Year.

By letter dated September 19, 2005, Northland submitted responses to Decision 13-2005, by filing the interim rate schedule (Rider K) and Rider E. The Board issued Decision 14-2005, dated September 26, 2005 approving Rider K and Rider E, for each community, effective October 1, 2005.

The Board, the Town and the Hamlet submitted information requests, to which Northland responded on October 14, 2005 (Ex. 5).

By letter dated October 20, 2005, Northland advised the Board that based on discussions with interested parties, Northland does not consider it likely that a comprehensive Negotiated Settlement could be reached regarding the GRA.

The Hamlet filed intervenor evidence on October 31, 2005 (Ex. 6). The Board, Northland and the Town submitted information requests to the Hamlet respecting its intervenor evidence, to which the Hamlet responded on November 14, 2005 (Ex. 7).

By letter dated November 21, 2005, the Town filed rebuttal evidence (Ex. 9).

2. PUBLIC HEARING

Public Notices of the hearing was advertised and scheduled for November 29 and 30, 2005 (Ex. 1). The hearing was held in the Town of Hay River.

During the course of a public hearing, members of the public who had not initially requested intervenor status are allowed to participate in the proceeding. At this public hearing, Ms. Lesli Fisher, President of the Hay River Chamber of Commerce made a presentation to the Board.

At the beginning of the 2nd day of the hearing, Northland provided responses to the undertakings given at the 1st day of the hearing.

The Board and interested parties agreed on dates to file written argument and written reply argument. Northland, the Town and the Hamlet provided their written argument and reply argument, as per the Board's schedule.

PHASE I MATTERS

3. REVENUE AND SALES

The residential energy sales forecast was determined by multiplying the forecast number of customers by the forecast consumption per customer. The commercial sales forecast consists of a two part process involving the determination of energy sales to existing customers and then a detailed review of all known or expected commercial customer additions or losses. The forecast for existing customers was determined based on the most recent number of customers and a three-year average historic monthly consumption per customer.

The Town submitted that it is not clear whether the lower than normal sales in the first 5 months of 2005 was due to above average weather, unbilled sales or other reasons. By including the first 5 months of actual sales from 2005, Northland has eliminated that risk over that period but has not adjusted its rate of return on equity accordingly.

The Town also submitted that Northland provided the monthly number of customers in Schedule 1 to BR-NUL-NWT-1(b) and confirmed that that spreadsheet was used to drive the revenue forecast. However, there were no additions shown in the spreadsheet for December of both years and thus only 16 new customers instead of 20 were added. Therefore, the 2006 residential sales are understated by 27,200 kWh (4 x 6,800) and 2006 revenues on existing rates are understated by about $5,400.

In Reply to the Town’s concern about the decrease in average consumption for residential, Northland submitted it is entirely appropriate for it to take into account the best information available to it and therefore the use of the 5 months of actuals in forecasting the 2005 average residential consumption is appropriate.

With respect to the number of residential customers not reflected in the revenue forecast, Northland stated that it is prepared to adjust its forecast for the number of customers to reflect the four customers inadvertently omitted in certain schedules, as well as the associated purchase power costs. This will be done as part of Northland's refiling.

The Hamlet noted that Northland presently does not temperature normalize sales. By using heating degree day data for each of Fort Providence and Hay River, Northland would be able to calculate the average usage per customer per degree day for each class and better predict usage patterns in any given month. The Hamlet indicated that the ability to predict usage pattern accurately would assist in the procurement of fuel in the spot market. The Hamlet submitted that Northland should conduct a study in this regard to be able to better predict usage patterns in any given month.

The Hamlet also submitted that it is unlikely that commercial consumption per customer will decrease or be flat from 2005 to 2006. Assuming 2005 forecast amounts are reasonable, most communities show a clear increasing trend in consumption per commercial customer, with the exception of Trout Lake, which shows increases in 2003 and 2004, with a decline in 2005 and 2006. The Hamlet submitted that the 2006 average commercial customer usage forecast for each community, with the exception of Trout Lake, should be increased over forecast 2005 levels by the percentage increase in annual commercial customer usage between 2004 and 2005.

With respect to the Hamlet's concern over weather normalization, Northland stated that it is a small utility, with a small workforce, that should not be burdened with the cost of doing unnecessary studies that are unlikely to provide any material benefits. Further, Northland submitted that its forecasting methodology, which makes use of prior historical averages, already implicitly factors in the impact of weather changes from year to year.

With respect to the Hamlet's concern over commercial sales, Northland stated that its forecast for commercial customer usage is contained in Information Response FP-NUL-NWT-4(a) Schedule 1 and shows total commercial usage increasing 3.7% in 2006 versus 2005. This forecast is based on the process outlined on pages 2-3 of the Application and provides Northland's best forecast for 2006.

The Board notes that Northland expects to correct the residential sales forecast and revenues to reflect corrected customer growth numbers in 2005 and 2006. Northland is directed to reflect this change in its refiling of the Application.

The Board notes intervenor concerns respecting temperature normalization of sales. The Board agrees temperature normalization of sales would provide the Company and interested parties greater assurance that the sales forecast is accurate particularly where partial year data is reflected in forecast sales. It may also assist in more accurately determining the impact on sales and losses of unbilled consumption at year-end.

The Board notes Northland’s view that temperature normalization is an added burden for a small utility. However, in the Board’s view, given that purchased power and fuel costs constitute significant elements of Northland’s revenue requirement, normalization of sales could provide a means for meaningful comparison of sales and sales per customer from year to year and help explain changes in line losses or unbilled consumption from year to year. Accordingly, the Board directs Northland to temperature normalize historical sales for the purposes of forecasting test year sales and use normalized sales for the purposes of determining the energy balance, including line losses, at the time of the next GRA.

The Board notes the Hamlet’s concern respecting the difference in the growth rates for commercial consumption per customer from 2005 to 2006. The Board also notes that the commercial forecasts were prepared based on a detailed review of all known or expected commercial customer additions or losses. Accordingly, the Board considers that there may be customer specific reasons for the differential growth rates for commercial consumption per customer from year to year. Therefore the reason for change in commercial forecasts for 2006 offered by the Hamlet may not necessarily apply in this instance. The Board considers other changes to the sales forecasts recommended by intervenors to be not material in the overall context of revenue forecasts. Accordingly, the Board will accept Northland's sales and revenue forecasts, subject to the change with respect to customer additions noted above.

4. PURCHASED POWER

4.1 Line Losses

Northland forecast line losses based on an average of the previous five-year loss percentage (2000-2004) for each community. Northland indicated that the following variables can impact the forecasted line loss:

- System Configuration;
- Conductor Size on Feeders;
- Voltage of the System;
- Load on the System;
- Kilometers of line within the Community; and
- Types of Transformers and Electrical Equipment used.

With respect to the Hay River System forecast line losses, the Town submitted as follows:

> "… there was a significant increase in total and distribution losses on the Hay River System in 2004, system losses increasing by 1.8% over the

> 1999-2003 average of 10.8% and distribution losses increasing by 1.4% over the 1999-2003 average of 4.2%. NUL was asked to explain why distribution losses in 2004 were so much higher than in all other years shown in Schedule 1 to HR-NUL-NWT-9-1. In Undertaking No. 1, NUL indicated that part of the increased losses was due to growth in billed sales (which should not affect the percentage of losses) and growth in unbilled sales estimated to be 104 MWh from 2003 to 2004. However, there still remained 584 MWh of unaccounted growth in losses that NUL attributed to possible energy diversion and the accounting for unbilled sales. There is simply no evidence in support of the energy diversion theory." (Town's Argument, p.3)

The Town considered that the distribution losses for 2004 cannot be relied upon, not even as part of the five-year average as suggested by Northland. The Town submitted that the 1999-2003 average of distribution losses should be utilized as the best proxy for distribution losses in Hay River for the 2005 and 2006 test years rather than the 5-year average including 2004. The Town submitted Northland should be directed to refile its Purchased Power Expense using the 1999-2003 average of 4.2% for distribution losses.

The Hamlet submitted that by using the average line loss experience of the last 5 years (2000-2004), any improvements that may manifest in reduction in losses in the test years are effectively rendered mute. The evidence is clear, for example, that in both Fort Providence and Trout Lake, initiatives were undertaken in early to mid-2005 to reduce line losses. In the face of these initiatives to curtail losses, it is somewhat surprising to see Fort Providence, for example, experience an increased line loss of 11.90% in 2005 relative to the 2004 loss factor of 10.90%. The Hamlet recommended that there should be at least a 10% reduction in line losses for Fort Providence.

The Hamlet submitted Northland agreed to undertake further study to look at the costs and benefits of improvements to the system that would mitigate these losses. The Hamlet recommended Northland should be directed to provide the outcome of this study and provide specific steps planned and undertaken with a view to reducing line losses in the diesel communities.

Northland submitted that it has initiated measures that will be implemented, primarily on a go forward basis, to assist in mitigating line losses in the future. Northland stated that it has adopted a practice of using a larger conductor to assist in this regard, but has not quantified the impact its efforts will have on actual line losses. Northland also observed that line losses increased with load growth and, therefore, there are two competing, offsetting factors that must be taken into account. Northland acknowledged that unaccounted for energy is comprised of two components, being line losses and unbilled revenues, but observed that the latter was not causing significant fluctuations as was the case in Northland Utilities (Yellowknife) Limited's (“**Northland YK**”) recent GRA.

The Board notes the material fluctuations in distribution line loss percentages from year to year as shown in HR-NUL-NWT-9-1(c) line 3 for Hay River and in Exhibit 25 line 4 for each of the diesel communities. Northland alludes to unbilled consumption, among others, as a contributory factor to yearly fluctuations in line losses. However, the Board shares intervenors’ concern that Northland has not adequately explained the reasons for the fluctuations in line loss percentages from year to year. The level of line loss percentages particularly in the communities Fort Providence, Trout Lake and Dory Point/Kakisa also concerns the Board.

In order to address the concerns over fluctuations in line loss percentages from year to year, Northland is directed to develop procedures for determining actual line loss factors for each year, which are reasonably reflective of the electrical line losses for that year. To the extent the unbilled consumption is a factor amongst others causing fluctuations in overall loss factors from year to year, the percent loss factor applicable to electrical losses should be identified separately from the loss factor applicable to other factors under the category of unaccounted for losses. Northland should institute the above procedures with immediate effect and explain how these procedures address the accurate determination of forecast loss factors, at the next GRA.

Northland is also directed to provide an engineering assessment of the level of line losses in each community given the community's particular system configuration and report on and reflect the outcome of the study in the next GRA.

5. DIESEL FUEL COSTS

5.1 Fuel Procurement

The Hamlet submitted that by using heating degree day data for each of Fort Providence and Hay River, Northland will be able to calculate the average usage per customer per degree day for each class and better predict usage patterns in any given month. The Hamlet indicated the ability to predict usage pattern accurately would assist in the procurement of fuel in the spot market. The Hamlet submitted Northland should conduct a study in this regard to be able to better predict usage pattern in any given month.

The Hamlet also submitted that simply because some communities receive fuel supply once a year and prices are paid on delivery, it does not mean Northland is engaging in any form of hedging. In fact, in this case, the entire year's fuel supply is based on spot prices, i.e. the price that prevailed on the delivery date. The Hamlet conceded there is no doubt that the supplier will be looking for a premium over spot prices in any form of a hedged transaction. However, the Hamlet believed that, from the customers' perspective, some extent of hedging provides for protection that payment on spot for 100% of fuel supplies maybe too high.

Northland submitted that there is absolutely no evidence to support a conclusion that the implementation of a partial hedging program would be practical or cost effective in the circumstances encountered by Northland. The additional costs associated with hedging small volumes of fuel in remote communities are likely to outweigh any speculative benefits that might possibly occur.

The Board notes the Hamlet's view that temperature normalization of average usage per customer per degree day for each rate class would enable Northland to better predict usage patterns in any given month, from the point of view of fuel procurement. The Board considers any systems that would assist in the balancing of supply and demand as well as provide fuel price forecast accuracy, without the need for frequent price reforecasts, would contribute to rate stability particularly in the context of Rider A for diesel communities. The Board notes the Hamlet's concern respecting rate stability resulting from quarterly adjustments to Rider A consequent upon fuel price changes. In light of these concerns, the Board expects Northland to consider the suggestions offered by the Hamlet as well as other options towards the goal of improving fuel price forecasts prepared in the context of Rider A applications so as to reduce the need for frequent price reforecasts. Further comments respecting Rider A are provided under Section 14.2.

5.2 Heat Rates

Northland stated forecast fuel efficiencies or heat rates are based on historical trends adjusted for the non-recurring use of less efficient units or for the forecast fuel efficiencies of any new engines forecast to be in service. During hearing examination, Northland acknowledged the impact on fuel efficiency resulting from the addition of a new generating unit in Fort Providence in 2006 is not reflected in the Application. In response to Undertaking 10, Northland indicated:

> "The heat rate calculation based on using a three (3) year average for the months of January to May of 2006 using the three (3) year average of 2002, '03, and '04, together with the forecast heat rate for June through December of including the new unit together with the remaining existing units would have resulted in a heat rate of 3.55 kilowatt hours per litre." (Tr., Vol. II; p.13)

The Board considers that, in accordance with Northland's stated method of forecasting heat rates, the forecast fuel efficiencies of any new engines forecast to be in service should be reflected in the forecast heat rate calculations. Accordingly, the Board directs Northland to adjust the 2006 heat rate calculation for Fort Providence to reflect the addition of the new generator in 2006.

5.3 Steps to Reduce Reliance on Diesel

The Hamlet submitted that it continues to be concerned about the total reliance on diesel as the only source of generation in the so-called "diesel communities". The Hamlet submitted that as long as Northland can recover its costs and earn a fair return on its investment in these communities, it has little incentive to find alternatives to diesel generation. The Hamlet noted that it is not only concerned about the fact that diesel costs a lot of money, but also about the negative environmental aspects of using diesel.

The Hamlet submitted that the Board should direct Northland to actively pursue any federal and territorial funding available to undertake a feasibility study to connect Fort Providence (and other diesel communities) to the hydro system. As well, alternate technologies should be investigated.

In response to the Hamlet's Argument, Northland submitted that there is simply no evidence on the record to justify the costs associated with conducting any such study now. Northland noted that it is a small utility with only 15 employees and less than 2,600 customers. The costs associated with such studies are likely to far outweigh any potential benefits, particularly in circumstances where there is no factual basis to support a view that any such benefits will be derived.

The Board considers the procurement of energy supplies at prudent costs to be a matter within its jurisdiction. The Board considers that Northland has a mandate and responsibility to take all necessary steps that would help minimize the cost of electricity supplied to its customers. Accordingly, Northland is directed to provide a preliminary assessment of feasible energy supply alternatives for diesel communities, including those referred to by the Hamlet, that may help alleviate the high cost of providing electricity supply to these communities, as part of its next resource planning cycle and provide Northland's recommendations thereon to the Board and interested parties by year end 2006. Following this filing, the Board may direct that further detailed studies or a further process be undertaken or may conclude that the matter needs no further action.

6. OPERATIONS AND MAINTENANCE EXPENSES

6.1 Labour Expense

The Hamlet submitted, despite a constant complement of 15 employees since 2003, Northland is forecasting significant increases in labour expenses over the test years. The explanations provided by Northland for the increases in labour expense, "that there is now a full compliment of employees, as opposed to prior years", do not reconcile with this constant number of employees of 15. (Hamlet Argument, p.16)

The Hamlet submitted that the increases are not justified and the labour forecast should be reduced 20% in each test year.

Northland responded that there is no evidence to support this suggestion.

Given the adjustments determined as appropriate in regards to the vacancy rate applicable in each test year, the Board is satisfied that the net labour forecast is reasonable for the test period.

6.2 Vacancies

Northland submitted that it is a small company in terms of the total number of employees and is forecasting a minor vacancy rate (.1 position) for 2005 and zero for 2006. If an employee were to leave during the test period, Northland indicated that it would have to backfill with a contractor or affiliate secondment, as well as hire a replacement to complete required work. Northland also noted that the arguments of that intervenors ignore the impact of recruiting and relocation costs related to vacancies during the test period and which have not been included in the forecast.

The Town noted actual vacancies averaged 7.2% over the years 2001-2004. While Northland's intent may be to fill all positions, the Town submitted that history shows this does not happen and recommended the vacancy rate of 7.2% be applied to the 15 positions in BR.-NUL-NWT-4(f), resulting in an average of 1.1 vacancies for each of 2005 and 2006. The Town also noted, in reply, that

Northland had the same opportunities to backfill in non-test years but did not do so.

The Board recognizes small fluctuations in the staffing levels of a smaller complement of employees may result in larger vacancy rates. The Board notes from BR-NUL-NWT-4 (f) that the vacancy levels ranged from a low of .5 FTE in 2002 to a high of 1.9 FTE in 2003 during the four-year period from 2001 to 2004. The average vacancy level during this period was 1.05. Given Northland's evidence that vacancies experienced in the past resulted in the Company not being able to complete certain critical maintenance work, the Board considers it would not be appropriate to use the experienced average to assess vacancy rates. Rather the Board considers the low end of vacancy rates experienced in 2002 may be more reflective of normalized vacancy levels. The Board agrees the opportunity to backfill positions would have been available to Northland during the historical period but does not appear to have been the chosen course of action. The Board directs Northland to use a vacancy level of .5 FTE in each of 2005 and 2006 and to reflect the appropriate reduction in labour, benefits and other expenses in its refiling.

6.3 Affiliate Charges in Operation & Maintenance (including Administration and Head Office Fees)

Northland indicated the Information Technology charges now reflect an I-TEK direct billing rather than billing through ATCO Electric ("**AE**"). This reclassification has an offsetting reduction in costs from AE and must be viewed together. Northland also noted it has been allocated a portion of the costs associated with implementation of the new Oracle financial systems. Northland also indicated regulatory and financial reporting charges are forecast to increase in the test year due to the additional workload.

Northland submitted that the Code of Conduct requirements mandated a change in the presentation and charging of certain head office fees, as well as the imposition of a 70% loading charge on labour costs incurred for services provided by AE. These costs do not contain any element of profit or return.

The Town submitted that there have been significant increases in total administrative costs since 2003. The Town indicated that it has concerns with several of Northland's explanations regarding year over year increases. The Town also submitted that the $54,000 estimated amount for preparation of the Phase II in this proceeding should be amortized over 4 years. Further, while Northland asserts that the $15,000 of clerical support plus $5,000 for fringe benefits from customer accounting would result in reductions, there is only a $6,000 reduction. The Town recommended that the net $14,000 increase related to clerical support from customer accounting should be disallowed.

The Hamlet noted that, as AE does not have an approved revenue requirement for 2005 and 2006, amounts included in Northland's affiliate costs might include untested amounts. To the extent the costs of AE are reduced by the Alberta Energy and Utilities Board ("**AEUB**"), the Hamlet submitted that the reductions should be flowed through to customers.

In response, Northland noted work performed by AE for Northland is required whether there is an active proceeding taking place at the time or not. Ongoing work for items such as the administration of various riders and deferral accounts is ongoing in nature.

The Board considers regulation and Phase II related expenditures are not likely to occur annually at the same level each year. Accordingly, the Board is not convinced the $27,000 cost in 2004 for regulation and Phase II activities is likely to be incurred at this level in each of 2005 and 2006. The Board considers it more reasonable to spread the costs identified as related to regulation and Phase II over the two-year test period. Therefore, the Board directs Northland to reflect a net reduction of $13,500 for this expenditure item in each of 2005 and 2006.

In terms of flowing through reductions in AE's affiliate charges following resolution of those costs by the AEUB, the Board has no basis to determine whether such an adjustment is likely to result in material changes and is satisfied the current forecast is based on the best information available at the time the forecast was prepared and available as at the time of the hearing.

The Board notes Northland's explanations for increases in administration costs from 2003 to 2004, which includes the addition of a casual employee at $14,000 and additional fringe benefits of $5000. The explanations for increases in 2005 over 2004 includes the addition of $12,000 for an employee returning from maternity leave, additional clerical support from customer service at $15,000 and fringe benefits increase of $5,000. The Board is concerned by the level of increases year over year and the explanations, which appear to be somewhat duplicative.

The Board notes the Town's view that the $15,000 of clerical support plus $5,000 for fringe benefits from customer accounting should result in corresponding reductions in customer service whereas there is only a $6,000 reduction. The Board agrees Northland has not explained why the increase in administration due to transfer of an employee does not result in a comparable reduction in customer service expense. In the absence of adequate explanation from Northland and in light of the addition of a casual employee in 2004 and a further addition of an employee returning from maternity leave in 2005, the Board is not convinced the proposed level of increases are justified. Therefore, the Board will accept the Town's proposal to reduce administration by $14,000. The Board directs Northland to reflect a net reduction of $14,000 for this item in 2005 and 2006.

6.4 Distribution Maintenance

Northland submitted that it provided a complete explanation for the requested increase in Distribution Account 87300 – Maintenance. The overall increase is due to a new hire, a new heat scan program and a new ground rod inspection program. Northland submitted that there is no double counting of the proposed expenditures and the full requested increase is required. Northland noted that certain activities, which did not impact upon the safety or reliability of the system, were simply not done or not done to the level that may have been desirable in prior years (due primarily to manpower shortages). Northland is now planning to return to the level of maintenance that is desirable and appropriate given that it will have a full complement. (Northland Argument, p.6)

The Town noted Distribution Maintenance is forecast to increase $101,000 in 2005 and $86,000 in 2006. The Town noted Northland's acknowledgement that it had counted $17,000 for heat scanning equipment twice in the explanation of increases. As a result, the Town submitted the $29,000 increase attributed to catch up on deferred maintenance should really be $46,000. The Town noted that Northland had also indicated in BR-NUL-NWT-5(b) that "Based on 2004 actual there is $37,000 of deferred maintenance which is being made up in 2005 and 2006." The Town noted Northland's explanation that this latter amount was the difference between a vacancy of 1.0 in 2004 and 0.1 in 2005 times the pay rate. The Town submitted that given that power linemen vacancies are noted in both Account 85300 Transmission Overhead Lines and Account 87300 Distribution Maintenance, in 2004, the difference must reflect only a portion of a lineman in each account.

The Town noted that it is not convinced that had the resources been available, either by way of contractor or employees seconded from an affiliate, that the $46,000 of distribution maintenance could and should have been performed in 2004. That maintenance would include both labour and materials and supplies. The Town submitted that the 2005 and 2006 distribution maintenance should be reduced by $23,000 in each test year to ensure that customers do not pay twice for those services. (Town Argument, p.8)

The Town stated that it can only conclude activities not done, or not done to a desirable level, should have been done in prior years and the costs to perform those activities were previously paid by consumers. “NUL has effectively deferred those activities to the test year and customers will pay for them a second time.” (Town Reply, p.3)

In response, Northland stated:

> “this suggestion is totally baseless and must be rejected by the Board. There is simply no basis upon which to conclude that any such “double-counting” has or will occur, particularly in the context of NUL’s actual experienced returns and the forward Test Year method of regulation.” (Northland Reply, p.9)

The Board is concerned that the Company may have deferred spending in non-test years to the current test period. Although the Board recognizes Northland’s explanation regarding the level of work done with existing resources, the Board considers it within Northland’s abilities to contract additional help if required to ensure the necessary level of work was completed. The Board does not consider it appropriate to defer necessary expenditures for the safety, reliability and upkeep of the system to test years. The Board considers distribution maintenance expenditures included in revenue requirement should reflect a normalized level. Therefore, the Board directs Northland to reduce its forecast distribution maintenance by $18,500, representing the amount indicated by Northland as catch up or deferred maintenance, in each of the years 2005 and 2006. (BR-NUL-NWT-5b)) The Board notes that the above adjustments would bring the level of expenditure under account 87300 during the test years more in line with the average expenditures over the 6 year period from 1998 to 2003 with some allowance for staffing increases, inflation and other identified increases specified in BR-NUL-NWT-4(b).

6.5 Special Studies on Kakisa Hydro and Mackenzie River Crossing

Northland indicated that these are high-level studies, which are designed to assess the feasibility of projects that will be of benefit to its service area. Given the nature of the studies, Northland is proposing to expense these costs instead of capitalizing them.

The Town noted that the Kakisa Hydro study involves an office study to estimate the capital cost and potential output of the site. Although the project is forecast to be complete in 2005, the Town stated that it does not appear the $10,000 expenditure will be made in 2005. The costs should be held in Plant Held for Future Use ("**PHFFU**") until a decision is made on whether to proceed.

With regard to the Mackenzie River Bridge Crossing, the Town submitted that there is no reason to proceed with the study until a final decision is made to proceed with the bridge. In the event the bridge project proceeds, any study expenditures should be placed in PHFFU.

Northland considered the Town's recommendation to put the costs of the Kakisa study in PHFFU inappropriate and inconsistent with the requirements of GAAP. In particular, Northland submitted that GAAP dictates these costs be expensed, as it is not certain the underlying project will proceed. If held in PHFFU, shareholders would pay the costs if an actual project were not ultimately undertaken. Northland also stated that studies, such as the Mackenzie River line, are appropriate, particularly where consideration of whether to undertake a project must be done in a timely manner. Northland submitted that it is incumbent upon utilities to undertake studies when opportunities could have material benefits for customers.

The Board agrees that the Company requires sufficient flexibility in its management to properly consider opportunities related to projects such as the Kakisa and Mackenzie River Bridge crossing which may result in benefits to customers. Given the uncertainty of whether the project might proceed and the level of costs involved, the Board considers Northland's proposed treatment of these expenditures appropriate. With regard to the timing of the Kakisa study, the Board agrees it is unlikely the forecast expenditure will be completed before the end of 2005 and directs Northland to move this expenditure to 2006.

6.6 Training and Meetings

Northland forecasted increased costs related to trainings and meetings for a new supervisor of administrative services to increase visits to communities to conduct public safety programs, energy conservation, etc. Neither the Town nor the Hamlet provided comment on this issue in Argument or Reply.

Having reviewed the evidence on this expense and the purposes of the program, the Board is satisfied the forecast level of expenditures for training and meetings is reasonable and is approved as filed.

6.7 Brushing

The actual and forecast expenditures on transmission and distribution brushing expenditures are as follows:

	Actual 2003	Actual 2004	Forecast 2005	Forecast 2006
Transmission brushing	12000	13000	27000	29000
Distribution brushing	26000	29000	52000	55000

Northland submitted that brushing costs were below forecast levels in past years primarily due to vacancies. Further, Northland hired an outside consultant to examine brushing activity who indicated that additional brushing was required to bring the system back to desired levels.

The Town noted Ouimet Cunningham's 3 Year Projection to get the brushing cycle on track was $75,000 per year. The Town went on to note Northland spent $42,000 in 2004 on transmission and distribution brushing even after receiving the report. The Town also noted that the average expenditure on distribution brushing during 1999-2004 was $40,000, $16,000 less than forecast for 2000.

The Town considered that Northland should not be compensated twice for the same work. The lack of staff to carry out the program is simply not an adequate excuse. The Town submitted that, in the current test years, Northland claims they will fill vacant positions by contractors or by seconding from an affiliate. In the Town's view, Northland did not maintain its brushing program since the last GRA and is now faced with a serious catch up situation. The Town noted Northland spent $30,000 less than it forecast in the 1999/2000 GRA on transmission brushing over the period 1999-2004. For distribution brushing, the comparable figure is $96,000.

The Town noted that, with reference to in HR-NUL-NWT-11(b), Schedule 1, page 2 of 2, Northland would be required to spend $75,000 per year from 2004-2006 to get the brushing cycle back on track. Northland's 2004 actual brushing expenditures were only $42,000 and adding the forecast expenditures for 2005 and 2006 totals $205,000 which is just slightly less than the Ouimet Cunningham estimate to get the brushing cycle back on track. The Town submitted that Northland should be directed to bring the brushing program back to the standard recommended by its consultant by the end of 2006. However, since Northland has been compensated through rates for $77,000 per year but has only expended $56,000 per year over the last 6 years, customers should not be asked to pay a second time. The Town estimated that if Northland is allowed to include $19,000 for brushing in each of the 2005 and 2006 test years, it will have been fully compensated for brushing over the period 1999-2006. (Town Argument, p.7)

In Reply, Northland stated it is clearly not asking customers to pay a "second time" for costs that were recovered in rates in past years. Northland submitted that it has under-earned on its approved return because it incurred the costs necessary to provide safe and reliable service. While Northland does not consider the results of the Ouimet Cunningham study as "mandating" any particular course of action, it does use the study as a guide to assist in focusing its brushing efforts. Northland has prepared forecasts based on the costs it expects to incur in order to conduct an appropriate brushing program for each of the Test Years. (Northland Reply, p.11)

Although the forecast level of brushing appears higher than in previous years, the Board is more concerned that the necessary work be undertaken and completed to ensure the safety and reliability of the system. In this instance, the Board is very concerned with the findings of the Ouimet Cunningham report and the apparent failure of Northland to carry out significant brushing work over the preceding years. The Board expects and directs Northland to ensure the necessary brushing work is undertaken to ensure the system's safety and reliability and to provide a comprehensive status report on the state of the work as part of the next GRA.

For the purposes of these proceedings, the Board notes the annual expenditure of $75,000 required in each of 2004, 2005 and 2006 to bring the brushing program up to date under a 3-year program set out in the Ouimet Cunningham report. The Board considers this level of expenditure may not necessarily reflect a normalized level of brushing expenditure given the comment in the Ouimet Cunningham report that the 2007/08 budget should be less, pending completion of the 3-year program. The Board also notes the actual expenditure of $42,000 in transmission and distribution brushing in 2004. This level of expenditure in 2004, as well as the expenditure levels that are significantly lower than what was forecast for brushing in the last GRA, support the Town's view that there is some catch up expenditure reflected in the 2005 and 2006 forecasts. However, considering all of the circumstances, including the need to bring the brushing program up to date, the Board approves transmission and distribution brushing expenditures totalling $75,000 in each of 2005 and 2006. Northland is directed to reflect this finding in its refiling.

6.8 Franchise Retention Costs

Northland included $21,000 in 2005 and $19,000 in 2006 for amortization of Franchise Retention Charges. As noted in the Town's Argument, these costs are described as primarily legal costs to negotiate the Hay River Franchise Agreements in 2000 and 2004. Northland indicated these costs are amortized over the term of the Agreements. However, the Town noted the initial $54,000 in 2000 should have been fully amortized by 2004 and the $32,000 for the 2004 renewal should be amortized at a rate of $11,000 per year. In any event, the Town considered these are more appropriately shareholder costs and should not be paid by customers.

Northland submitted that the Town's proposed approach is entirely inappropriate as the retention of the franchise is critical to Northland's efforts to minimize costs for all customers. The loss of economies of scale associated with such a franchise loss would cause dramatic increases in costs.

The Board considers that the addition and retention of franchise areas provides the opportunity for benefits to customers of the utility in terms of customer growth and economies of scale. While there are also potential benefits to shareholders resulting from growth in the business, the Board considers the operation, including renewals, of franchise agreements an ordinary part of the utilities' business and properly included in the utility's operating expenses. That being said, the Board agrees with the Town's assessment that the 2000 Agreement should have been fully amortized by 2004 when it was again renewed. Therefore, the Board directs Northland to reduce the amount included for amortization of the Hay River franchise renewal to $11,000 per year.

6.9 Hearing Cost Reserve

Matters related to the hearing cost reserve are addressed in the No Cost Capital portion of this Decision.

7. TAXES OTHER THAN INCOME

The Board notes the total of property taxes included in revenue requirement amounts to $41,000 in 2005 and $45,000 in 2006. (Schedule 1.1) However, the total property taxes shown in response FP-NUL-NWT-8 are $34,200 in each of 2005 and 2006. The Board directs Northland to reflect the correct numbers for property taxes in revenue requirement in its refiling.

8. DEPRECIATION

In its Application, Northland filed a depreciation study prepared by Mr. Kennedy of Gannett Fleming. The Town suggested that Northland's use of monthly plant balances for the forecasts may result in a mismatch between the Company's forecast depreciation expense and booked depreciation expenses if the latter is based on year end plant balances. However, the Board notes Northland's position is actual account depreciation rates are multiplied by actual monthly account plant balances to arrive at the monthly actual depreciation expense. In view of the clarification provided by Northland, the Board does not consider a change in the proposed depreciation calculation is necessary.

With regard to survivor curves, Northland proposed the continued use of a 40-R3 Iowa Curve for Account 457, Transmission Substation Equipment. No change to this account was proposed by Northland due to the lack of adequate retirement data.

The Town submitted that the 50-R3 curve used by AE and provided in HR-NUL-NWT-14(a) is a better visual fit for account 457 than the 40-R3 curve provided at page III-21 of the Depreciation Study. The Town submitted that the Company did not adequately support the 40-R3 curve proposal for account 457. The Town noted that the Company relied on comparators from NWTPC and Yukon Energy Corporation, stating that they have similar physical forces of retirement to Northland. However, the Town that submitted, there is no evidence to support this assertion other than some anecdotal references to sizing, weather and load considerations. The Town submitted that the account 457 depreciation curve should reflect the one used by AE.

The Board notes the Town's concerns with respect to this account and considers the explanations in relation to northern peer comparators and to AE provided by Northland do not adequately demonstrate that the continued use of the 40-R3 curve is appropriate for this account. Accordingly, the Board directs Northland to provide further evidence in relation to account 457 with additional peer comparisons together with explanations for differences, as part of its next depreciation study and/or technical update. Given limited data on actual retirements for this account, and given the peer comparison to Northern Utilities provided by Northland, the Board is prepared to retain the 40-R3 curve for purposes of this test period.

For Account 474, Distribution Overhead Conductor, Northland proposed to increase the average service life from a 40-R2 Iowa Curve to a 45-R3 Curve. The Board notes the Town's suggestion that the 50-R2.5 Curve appears to fit retirements on this account better than the proposed 45-R3 curve. On the other hand, Northland's position is that the 45-R3 curve fits better in the mid-life portion of the asset account. Northland acknowledges that there is no clear fit for this account but, considering the two northern peer utilities, the 45-R3 is more appropriate. In view of this evidence, the Board will accept Northland's recommendation of 45-R3 for account 474.

Finally, Northland proposed a change in Account 479.10, Distribution Line Transformers, from a 27-R2.5 Curve to a 30-R2.5 Curve. The Town argued that the 37-R2 curve provides a better fit through the 0-15 year interval and a much better fit through the 30 – 40 year interval. Northland stated that only in the periods of insignificant retirement ratios post age 30 does the IOWA 37-R2 provide a better fit. Northland suggested retirements beyond age 30 are not statistically significant as less than 2.5% of the plant would still be exposed to retirement. The Board is not convinced the use of the 37-R2 Curve is superior to the recommended 30-R2.5 Curve and approves the proposed change from the 27-R2.5 Curve to the 30-R2.5 Curve.

9. RETURN

9.1 Capital Structure and Return On Equity

Northland requested a return on common equity of 10.75% in each of the test years based on its actual common equity ratio. Although prepared to use the 9.5% return utilized by the AEUB as a starting point for Northland's return, Northland submitted that it is a very different utility from those located in Alberta with different risks. Northland noted that its functions include generation and retail, recognized as being riskier functions than transmission and distribution. Northland also indicated that it has a concentration of customers in one franchise and has little diversification with respect to franchise retention. With regard to the equity ratio, Northland suggested a utility of its nature and size warrants an equity ratio far in excess of 40%, and in the range of 48-55%.

On the issue of equity return, the Town submitted:

> "NUL accepted the 9.5% starting point knowing full well that rate was based on 3 and 12-month forward long Canada rates of 4.9% and 5.2% as forecast in November, 2004, but which had dropped to at least 4.5% and 4.9% or 30-40 basis points by March, 2005, and further to 4.2% and 4.6% by July, 2006. Clearly, the 9.5% start point was generous to NUL at the time the application was filed." (Town Reply, p.4)

The Town noted that, while Northland submits it would be inappropriate to selectively update this portion of the Application by considering the more current consensus forecasts, the AEUB has accepted such updates up to the time of the hearing. Moreover, the Town suggested consideration should also be given to the recent AEUB decision concerning the 2006 generic return on equity, setting the return at 8.93%.

In discharging its mandate to determine fair and reasonable rates, the Board considers it prudent to utilize the best information available as at the time of the hearing in making its determinations. In this case, the Board notes the decline in long Canada rates from the November 2004 consensus forecast. Although not the only factor to be considered, the Board agrees the 9.5% starting point for Northland is generous. However, taking into account some of the differences in risk between Northland and other utilities, including its integrated structure, generation and retail components and focused franchise centre, the Board considers a return of 9.5% for 2005 is appropriate and fairly balances the interests of shareholders with those of consumers.

With regard to 2006, the Board notes the AEUB's decision concerning the 2006 generic return on equity. As the change in the consensus forecast would largely be accounted for in the 2006 return rate, the Board does not consider any further adjustment is required in this regard. However, again, taking into account the risks relative to Northland, the Board considers a return on equity of 9.5% in 2006 is also appropriate.

Northland is directed to reflect a return on equity of 9.5% for 2005 and 2006 in its refiling.

Although the Board agrees that there are differences between Northland and AE, differences of varying degrees and scope will always exist between companies. In this instance, while Northland's functions include generation and retail, the Board notes that the scope of the generation function is not extensive and may be offset, to some extent, by the fact a significant portion of Northland's power supply is purchased energy. Given the integrated nature of Northland, and considering the risks it faces relative to comparable utilities, the Board considers the aforementioned return applied to the Company's actual equity ratio in the range of 39% to 40% is reasonable for the test period.

9.2 Customer Deposits

The intervenors raised the issue of whether customer deposits should be included in Northland's no cost capital. With regard to customer deposits, Northland stated that these serve as security for unpaid bills and are required to be available to either be refunded to customers or to actually apply to the bills in the event of a default. Although the total remains approximately the same from year to year, Northland submitted that the funds are needed to be available to repay them when they leave or default on payment.

The Town submitted:

> “… Given the overall level of consumer deposits, the likely quantum of any particular refund and the sources of short-term capital available to the company, it does not seem necessary nor efficient to maintain a separate bank account when such funds could be used to fund longer term obligations which carries a higher cost of capital. Hay River submitted that $90,000 of estimated consumer deposits should be included in the capital structure for 2005 and 2006 at a rate of 2.54% being the current interest rate paid on consumer deposits.” (Town Argument, p.15)

The Hamlet submitted:

> “Customer deposits, net of the amounts NUL expects to apply towards uncollectible accounts, should be recognized as a reduction to NUL’s working capital. The use of these funds effectively reduces the total amount of necessary working capital otherwise necessary to run NUL’s operations. Fort Providence also submitted that NUL should be allowed to include the forecast interest costs payable on such deposits.” (Hamlet Argument, p.21)

Although the make up of these funds may fluctuate over time as a result of changes in customers and the payment and receipt of funds into and out of this account, the Board notes that the quantum of these deposits appears to be growing in a stable manner year over year. While the Board recognizes a portion of the funds may be payable to Northland for uncollectible accounts during the test period, the Board also considers it highly unlikely that a substantial portion of the net funds in the account would be paid out in a short period in the absence of the Company changing its policy on the requirement for deposits or otherwise terminating its business. Accordingly, the Board agrees with the position advanced by the Town, namely customer deposits, net of amounts Northland forecasts to apply towards uncollectible accounts, should be included in the Company’s capital structure at a cost rate reflecting the interest payable on customer deposits. The Board directs Northland to reflect this finding in its refiling.

9.3 No Cost Capital

9.3.1 Deferred Pension Liability

No cost capital includes the deferred pension account. Northland proposed to transfer $29,000 in each of 2005 and 2006 into the deferred pension account reflecting the accrual of liabilities with respect to other post employment benefits (“**OPEB**”).

Northland indicated:

> “…these benefits are expensed for rate making purposes according to General Accepted Accounting Principles. However, the accrued amounts are <u>not</u> deductible for income tax purposes and, therefore, are factored out of the income tax calculations. NUL confirmed that these amounts are not capitalized...” (Northland Argument, p.12)

On this issue, the Hamlet indicated:

> “…with respect to OPEB is two-fold. Firstly, while most of its accounting and regulatory treatment for all other pension items is consistent with its parent ATCO Electric, the matter of OPEB is the only exception. For example, the parent is on a cash basis with respect to the Defined Benefit Plan due to the surplus in its plan. NUL’s DB Pension Plan, is for the “North of 60 employees…so that NUL and (NWT) are part of a separate pension plan” and this pension plan currently has a surplus of about $1.7 million, and hence, NUL is also on a cash basis for the DB Plan. Likewise, both NUL and AE are on a cash basis with respect to the DC Plan.
>
> Next, when we look at the continuity schedule of the OPEB deferral account, it becomes evident that NUL has been collecting from customers

> amounts with respect to OPEB on an accrual basis since 2001, and has accumulated a total of $134,000 to December 31, 2004 with nil payments for this expense to date. If allowed to be on an accrual basis for the test years, the collection will balloon to $192,000 by December 31, 2006. Note that there is no forecast of payments out of this account for the test years either.
>
> Fort Providence recognizes that the balance accumulating in the Deferred Pension Account benefits ratepayers through a reduction in the return. However, there is no need to pre-fund the OPEB expense. The clear evidence is that there have been no payouts for the last at least 6 years (since 1999) for which information is provided in this GRA, and there is no expected payout for the next 2 years 2005-06 either. Fort Providence is of the view that consistent with the practice adopted by its parent, NUL should record OPEB expense on a cash "pay-as-you-go" basis." (Providence Argument, p.17)

In reply, Northland submitted:

> "…NUL considered that compliance with GAAP is extremely important and that, if a divergence in treatment is to occur, it be explicitly justified in the circumstances based on persuasive evidence. As well, there is simply no evidence before the Board which would indicate that the impact on NUL of switching to a cash basis would be consistent with the implications of adopting such action for ATCO Electric." (Northland Reply, p.22)

The Board notes the Hamlet's concern that OPEB for north of 60 companies is treated on an accrual basis and this treatment is different from that used by Northland's parent for its employees. The Board also notes that Northland uses a cash basis for the defined benefit pension plan due to the existence of a surplus in this plan. The Board notes that no OPEB payments are forecast to occur during the test years and under these circumstances the entire forecast OPEB contribution to the deferral account is subject to tax gross up (ie: not deductible for tax purposes) during the test years. This results in current customers providing not only the funding but also the associated taxes. Had there been forecast payments out of the fund in 2005 and 2006 the current customers would benefit from the associated tax deductions. The Board is concerned the continued funding of the OPEB account without payments out of the fund may lead to intergenerational inequities between current customers and future customers. Considering the surplus in the OPEB fund, the Board considers it appropriate to suspend accruals to the OPEB account for the two test years. Northland is directed to address why it considers it appropriate to continue to use the accrual basis for OPEB at the next GRA, given the use of the cash basis for other components of pension costs and the tax impact of accrual accounting for OPEB noted above. Northland is directed to adjust its filing to reflect the suspension of funding to the OPEB account in 2005 and 2006.

9.4 Deferred Charges and Credits

9.4.1 Hearing Cost Reserve Account

Northland submitted that the hearing cost reserve may, at any point in time, have a negative or positive balance and, therefore, should not be included as part of no cost capital. Instead Northland proposed the inclusion of the balance in the hearing cost reserve as part of deferred charges and credits. The Northland proposed treatment has the effect of reducing the 2005 and 2006 rate base by the mid year balance in the hearing cost reserve.

The Town submitted that the reserve should be brought to nil, thereby eliminating consideration of its use as no cost capital. The Town went on to indicate a provision of $3,000 per test year would bring the balance of the Reserve to nil by the end of 2006.

Northland agreed with the principle of targeting a zero balance for the hearing cost reserve. However, Northland indicated that the $47,000 provision should be maintained in order to provide for contingencies.

The Board considers the Northland proposed provision of $47,000 per year may be necessary to cover the contingencies related to hearing costs. Accordingly, the Board approves the $47,000 provision in each test year as proposed by Northland. The Board expects Northland to continue to transfer $47,000 to the hearing cost reserve each year following the 2006 test year, until the next GRA.

9.4.2 Reserve for Injuries and Damages (RID)

The Hamlet presented a number of concerns with regard to the criteria for claims to be included within the RID.

The Hamlet recommended that the Board direct Northland to amend the RID accounting policy to specifically state that only claims clearly and demonstrably outside management's control and not reasonably preventable or foreseeable are to be eligible for the RID. The Hamlet also submitted that losses due to events arising from gross negligence on the part of the Company or events that are compensated through the return on equity should not be eligible for RID treatment. The Hamlet submitted that Northland's current policy invites management to engage in potentially lax operating practices, methods and acts with the customers footing the bill. Approving Northland's current RID policy in this manner is also inconsistent with the practice approved by the AEUB for other utilities it regulates. The Hamlet stated that Northland should be required to provide, as part of its refiling, a complete accounting policy with respect to RID with the addition of the criteria as noted in the Hamlet's Argument (Hamlet Argument, p.24).

Northland noted that there is no evidence regarding the impact such a change would have on Northland's risk profile. Further, as no claims are forecast for the test years, this matter has not been specifically addressed in Northland's Application.

Notwithstanding the above, Northland indicated that it is prepared to monitor the evolution of the treatment of reserves similar to its RID in other jurisdictions, evaluate the applicability of any such changes to Northland and report on same to the Board in the context of Northland's next GRA. (Northland Reply, p.24)

The Board considers that there is merit in ensuring the criteria for charges to the RID are appropriate, even in the absence of forecast charges. Noting Northland's offer to address this matter, the Board directs Northland to address the criteria for charges to the RID account at the next GRA, having regard to the criteria identified by the Hamlet in these proceedings.

9.4.3 Plant Maintenance Reserve

Northland submitted that this account is to mitigate the impact of major overhauls by spreading out the costs over time. Northland stated that it is requesting to increase the annual write-off from $50,000 to $100,000 to reduce the balance in this reserve account. Further, Northland submitted that the reserve is part of rate base and that the Hamlet's suggestion the reserve is not financed with the weighted average cost of capital is unsupported.

In its Argument, the Hamlet submitted:

> "Maintenance expense increases including amortization of the Plant Maintenance Reserve account are increasing by $179,000 in 2005 over

> 2004 actual levels or 33.6% and $174,000 in 2006 over 2004 actual levels or 32.7%. Fort Providence submitted these increases are too high and cannot be explained by an increase in one additional line man. It is submitted that this provides further support for the labour expense reductions set out above under operations and maintenance expense. Fort Providence further submits, that the allowed amortization of the Plant Maintenance Reserve Account should be reduced by $50,000 in each of the test years." (Hamlet Argument, p.27)

The Board notes that the charges to the plant maintenance reserve averaged about $40,000 per annum in the period 1992 to 1998 but the annual average increased to about $100,000 in the period 1999 to 2004. (BR-NUL-NWT-7) The Board considers the existence of a deferral account while mitigating utility risk may not necessarily provide a strong incentive for cost control. For this reason, the Board is concerned by the increase in the level of average plant maintenance expenditures. In view of this concern, the Board directs Northland to demonstrate that the level of expenditures charged to the deferral account with respect to each type of maintenance (overhaul, top end overhaul) for the different plants are reasonable by reference to suitable benchmarks derived from other Northern utilities at the next GRA. Given the average expenditure level of about $100,000 in the period 1999 to 2004, the Board will approve the requested increase in the amortization amount to $100,000 for 2005 and 2006.

With respect to the cost of financing the plant maintenance reserve, the Board considers the plant maintenance reserve to be no different than any other component of working capital. Accordingly, the Board considers it appropriate to allow the plant maintenance reserve to be included in rate base, earning the same rate of return as other rate base assets.

9.5 Working Capital

The Hamlet submitted that Northland should be directed to incorporate the impact of the credit management system on revenue lag and accordingly reduce the revenue lag days in 2006. The Hamlet stated that since there is no evidence on the record with respect to the impact of this system, Northland should be directed to determine the impact of the credit management system on working capital and incorporate any changes in its compliance filing.

The Board notes Northland's view that implementation of the new credit management system would have an impact on revenue lags. (Tr., Vol. I, p.281-283) The Board considers that since the cost of implementing the credit management system is included in the Application, the corresponding working capital related benefits should also be reflected in the forecasts during the test period. Accordingly, the Board directs Northland to reflect the impact of the credit management system on forecast revenue lags, in its refiling Application.

10. CAPITAL ADDITIONS

Northland indicated that its capital budget is comprised of new extensions, distribution improvements, street and sentinel lights, meters, transformers, generation and general plant and equipment. The forecast capital additions are slightly below the 2004 actuals.

10.1 Distribution Extensions

With regard to new Distribution Extensions, the Hamlet noted that historical data indicates Northland over forecast new extensions in 1999 by $15,000 and 2000 by $49,000. As Phase I applications were not filed for the period 2001-2004, there is no data on the variances between forecast and actual. The Hamlet submitted that Northland is unable to explain variations in costs for different projects. Given the inconsistencies and history of over-forecasting, the Hamlet recommended a 20% reduction in the 2005 distribution extensions forecast.

In reply, Northland submitted that the Hamlet’s proposed reduction is arbitrary. With regard to the history of over-forecasting, Northland noted the period was covered by a ‘package deal’ negotiated settlement with no line items for rate base additions. Northland submitted that the Hamlet’s position ignores actual costs for new extensions have increased every year during the period 2001 to 2004. On unit costs, Northland noted each development has different characteristics driving the price. Regardless, new extensions referenced by the Hamlet are completely offset by customer contributions with no impact on rate base or revenue requirement.

Although the Board notes the forecast level of expenditures appears to increase significantly in 2005 before returning to levels similar to the average of previous years, it does not consider there is sufficient evidence to conclude Northland’s forecasts demonstrate a tendency towards over forecasting. With regard to the differences in unit costs, the Board recognizes that there may be some differences in the costs relative to different projects. While the Board does not consider a reduction in the forecast appropriate, in future, it will expect Northland to be able to provide further details on the unit costs for each project, including a full description as to the reasons why costs related to a project may vary materially from costs for a project of similar description or type.

10.2 Sentinel Lights

The Hamlet noted Northland forecasts $6,000 for sentinel lights in each of 1999, 2000, and the two test years. No amounts were expended on sentinel lights in 2001-2004. Based on Northland's failure to spend amounts over the 2001 through 2004 period, the Hamlet submitted that the sentinel light forecast should be denied in full.

In response, Northland submitted that the proposed reduction is arbitrary and there is no evidence demonstrating that this forecast is not reasonable.

The Board is concerned that Northland has not provided any reasons as to why expenditures on sentinel lighting is required in the test years notwithstanding the absence of expenditures related to this item from 1999 to 2004. In the absence of evidence supporting the proposed change in spending levels, the Board considers it likely the current forecast incorporates some level of catch up from prior periods. However, it is not clear to the Board whether all of the forecast work will be completed given the pattern of expenditure in non-test years. The Board considers therefore the forecast should be reduced by 50%. Accordingly, the Board directs Northland to reduce the forecast for sentinel lighting to $3,000 in each of 2005 and 2006.

10.3 Meters

The Hamlet recommended that the Meters forecast be reduced by $5,000 in each year as the average expenditure over 2001-2004 was 4,800 and the forecast in 1999 was 12,000 and $8,000 in 2000. Again, Northland submitted that the recommended reduction is arbitrary.

The variances in the level of expenditures in non-test periods relative to test periods are matters of concern to the Board as previously discussed in relation to sentinel lighting. In this instance, there is no evidence justifying the increase in spending from the prior periods. Accordingly, the Board considers a reduction in the Meter forecast to $6,500 in both 2005 and 2006 appropriate to reflect the average level of expenditures over the period 2001 to 2004 while recognizing some increase in costs over that same period. The Board directs Northland to reflect this finding in its refiling.

10.4 Office Computer Equipment

The Hamlet noted that Northland over-forecast office computer equipment by $1,000 in 1999 and $8,000 in 2000, or by 80%. In 2001 through 2004, Northland did not make any expenditure with respect to Office Computer Equipment. The Hamlet recommended Northland's forecast for 2005 be reduced to $2,000.

In reply, Northland submitted that the Hamlet ignores the Company's use of computer equipment services during the non-test period; instead of purchasing computer assets.

While the pattern of expenditures in the non-test period is of concern, in this instance, the Board is satisfied there is sufficient justification concerning the variation in spending on this type of asset during the non-test period. The Board approves Northland's forecast of Office Computer Equipment as filed.

11. INCOME TAX

11.1 Rainbow Type Expenses

Northland indicated that it is not proposing a deferral account for Rainbow type deductions, as it does not see any basis upon which such deductions are available to Northland.

Northland submitted that the approach taken by it is prudent and limits the exposure to customers by ensuring that they are not exposed to the potential interest and penalty charges associated with disallowed deductions. As also noted, customers still get the benefit of the income tax deductions over a number of years through the claims for capital cost allowance, instead of in the first year. (Northland Argument, p.15)

The Hamlet noted that Northland's parent, AE, recently indicated it filed amended tax returns claiming a number of items as capital repairs. Although not all items were approved by Canada Revenue Agency ("**CRA**"), the Hamlet submitted that Northland's views on the eligibility of items for Rainbow treatment are overly narrow and recommended a deferral account for Rainbow expenses to refund or collect differences between placeholder amounts and actual amounts claimed as tax deductions for capital. The Hamlet went on to list projects and costs included in AE's deferral account and recommended, at a minimum, all similar Northland projects be included in the proposed deferral account.

In addition, the Hamlet recommended Northland provide a detailed project-by-project submission of why certain transmission and distribution capital expenditures in excess of $5,000 are treated as repairs; whereas others are capitalized for income tax purposes. Placeholder amounts in the deferral account would be based on this review.

Finally, the Hamlet suggested that Northland obtain an advance tax ruling on these issues, if necessary.

The Town supported the position of the Hamlet on this issue.

In its reply, Northland submitted that its position is based upon the direct experience of its parent company in determining the appropriate course of conduct for the assessment and treatment of these capital repair costs. Northland indicated that it fully understands the criteria that are necessary for eligibility for a Rainbow type deduction and has systemically applied these criteria to Northland's forecast capital repair costs. (Northland Reply, p.28)

Northland went on to indicate its concern that the Hamlet is ignoring the potential interest and penalty costs associated with a disallowance of unqualified deductions by the CRA and noted this is an issue of timing on the writing-off of expenses. With regard to the proposed study, Northland suggested the costs would outweigh the benefits.

As neither Northland or the Hamlet can unequivocally determine what CRA will, or will not, allow for Rainbow treatment, the Board is not convinced customers should be resigned to accepting the write-off of potential Rainbow type expenditures over time. Accordingly, given the uncertainties over the claims for Rainbow type expenses, and noting the establishment of a deferral account for this specific purpose for Northland YK pursuant to Decision 12-2005, Northland is directed to propose a deferral account for capturing any benefits resulting from Rainbow type claims during the test period, along the lines approved for

Northland YK as part of its refiling application. For the purposes of the deferral account, the same criteria for claiming Rainbow type expenses should be used for Northland as used for Northland YK.

While the Board recognizes a review of the type recommended by the Hamlet may involve the Company's resources, given Northland's position that it has already considered the eligibility of its capital expenditures for Rainbow treatment, the Board's view is that completion of a more formalized study should only require marginally incremental effort and cost. At the time of its next GRA, the Board directs Northland to provide a detailed assessment of transmission and distribution capital maintenance expenditures in excess of $5,000, indicating which, if any, of the Rainbow criteria each expenditure meets. In determining which costs should be considered, Northland should have reference to examples provided by other utilities in Alberta and the North where similar reviews have been undertaken. Based on that review, the Board will address the issue of whether continuation of a deferral account is warranted and any placeholder amounts.

With regard to the Hamlet's recommendation that Northland obtain an advance tax ruling, the Board does not consider it appropriate to provide such a direction in this instance but requests Northland investigate the timing, costs and viability of such an exercise as part of the foregoing report.

11.2 Engineering, Supervision & General (ES&G) Costs

Northland submitted that the year-to-year ES&G costs are relatively flat and the changes in the overall provisions are caused by changes in customer contributions. However, the Hamlet noted that Northland is not able to provide the basis for the allocation of the ES&G amounts as between UCC classes.

The Board considers the allocation recommended by the Hamlet is not unreasonable, should not result in significant costs, and would be of assistance in examining the income tax impacts related to this item. Therefore, the Board directs Northland to provide the basis of allocation of ES&G amounts between the UCC classes in its next GRA.

PHASE II MATTERS

12. COST OF SERVICE

In BR-NUL-NWT-13(d), the Board requested Northland to comment on a direction provided in Decision 12-2005 respecting Northland YK to review all classification factors to determine if they remain appropriate and to reflect the results in the next Phase II application.

In response, Northland indicated if the Board deems it appropriate to review all classification factors, Northland would be ready to carry out the directive. In order to mitigate the economic impacts associated with such a study, Northland would investigate the possibility of a joint study with Northland YK in an effort to spread the costs across a greater number of customers.

The Board directs Northland to review all classification factors used in the cost of service study in conjunction with a similar study for Northland YK and provide the results as well as reflect the findings in the next GRA.

13. RATE DESIGN

13.1 General

Northland indicated that it used rate design criteria similar to those utilized in its previous Phase II application. Northland stated that the criteria used in the design of the proposed rates are as follows:

- Recover the total forecast revenue requirement by rate zone (community).
- Utilize the cost of service allocations of the revenue requirement.
- Avoid undue discrimination between customer classes.
- Consider the rate levels, structures and policies of other utilities, particularly those of similar load and service conditions.
- Promote ease of understanding and acceptance by customers, as well as ease of administration and economy of billing.
- Recognize the level and structure of existing rates.
- Promote efficient and cost effective use of power through price signals built into the rate structure.

For the 2006 test year, Northland proposed to recover the deficiency using individual rate zone Riders (Rider R) on the 2005 base rates. A Cost of Service study was not performed for 2006 and therefore to determine the individual riders, the net revenue requirement was allocated to the rate zones and rate classes using the following method:

1) Determined the total non-fuel cost by removing the total fuel and purchase power costs of $2,630,000;

2) Removed the incremental revenue requirement impact of the new Fort Providence generator amounting to $45,702;
3) Determined the non-fuel cost per rate zone by allocating the net 2006 non-fuel Revenue Requirement using the ratio of the 2005 non-fuel cost per rate zone over the total non-fuel cost;
4) Added $45,702 to the Fort Providence non-fuel Revenue Requirement to reflect the capital generation addition (Schedule 3.9);
5) Allocated the total non-fuel cost per rate zone to the respective individual rate classes based on the ratio of the 2005 non-fuel cost per rate class over the total non-fuel cost for the rate class;
6) Added on the respective fuel and purchase power costs per rate zone as provided in Phase I Schedules 3.1 and 4.1.

The 2006 impact on the Fort Providence non-fuel revenue requirement due to the addition of the new generating unit as set out in Schedule 3.9, was amended in Northland's letter dated November 22, 2005 to $32,130. (Revised Schedule 3.9)

13.2 Fort Providence's Capital Zone and Postage Stamp Proposal

The Hamlet stated that, using the revised Schedule 3.9 provided by Northland, the proposed rate base addition resulting from the new generating unit alone causes a 3% increase to the 2006 Revenue Requirement. Put another way, just one large capital addition contributes about 32% to the total increase in the cost of service to Fort Providence in 2006 ($32,130/(1,180,595-1,081,234)). The Hamlet considered this to be a significant portion of the total rate increase to Fort Providence.

In view of its concern about the impact of new capital additions on the revenue requirement and rates of diesel communities, the Hamlet submitted evidence suggesting that the Board should consider the establishment of a capital rate zone as a means of mitigating rate shock resulting from diesel-related generation additions. Under the capital zone proposal, the cost of new diesel generation additions would be systematized as part of the diesel generation capital related costs across all communities including the Town of Hay River. The Hamlet also suggested that the capital zone averaging concept outlined above for new generation additions may be extended to existing diesel generating plant as well. As a further step in the continuum of rate averaging, the Hamlet suggested the Board should consider postage stamp rates across the entire service territory of Northland.

In support of its proposed postage stamp approach the Hamlet, in its filed evidence, stated that the principle of cost causation suggests that the customer must pay the costs he gives rise to. The Board must ask how equity and fairness is fostered in the existing rate design when customers who reside closer to a natural resource (that is, hydro, which belongs to all of the residents of NWT) get a preferred rate simply for no other reason than by happenstance i.e. by virtue of their proximity to that resource. It is not that they cause less costs by their actions; lower costs result from the availability of cheap hydro power. The Hamlet noted that there is no basis in cost causation to suggest that just because the communities are not interconnected, postage stamp rates are not appropriate. The Hamlet provided examples of other jurisdictions where, in its view, the postage stamp concept has been applied.

The Town filed rebuttal evidence in response to the Hamlet's evidence, which stated that until there is specific legislation that directs the Board to require hydro communities or lower cost diesel communities to subsidize higher cost diesel communities, the Town sees no reason to cause the Board to depart from its findings in Decision 5-95. Clearly, any action with regard to postage stamp rates should await the Government's review, changes if any to the legislation and input from all affected parties, presumably following a detailed review by the Board.

The Hay River Chamber of Commerce made a submission expressing concern over the impact of any form of rate averaging between Hay River and other communities on the Hay River economy.

Northland submitted that, while it clearly understands the proposal brought forward by the Hamlet, it does not support the implementation of the proposed diesel generation capital rate zone. Northland submitted that the implementation of a capital rate zone will deviate from the community cost of service based rates and will cause additional cross-subsidization between communities. Northland submitted that the issue of a capital rate zone has been examined previously by the Board (when brought forward by Northland itself) and was not accepted by the Board (Decision 6-96).

The Board has given due consideration and weight to the evidence and testimony of the Hamlet as well as that of the Town. The Board continues to hold the view expressed in Decision 3-2003 that given the absence of a physical system integrating hydro and diesel communities, the creation of any form of cost averaging between hydro and diesel communities would be contrary to the principles of cost causation and rate making (Decision 3-2003, p.31). Accordingly, the Board considers the Hamlet's capital zone and postage stamp proposals are not consistent with the principles of cost causation and will therefore not accept these proposals.

The Board also expressed the view in the same Decision that rate design criteria are intended to balance the move towards cost based rates while mitigating rate shock, (Decision 3-2003, p.31) Accordingly, the Board considers any concerns respecting rate shock should be addressed through the application of the rate design criteria rather than through any adjustments to the cost of service study.

The Board asked the Hamlet by way of an information request to identify other mechanisms for mitigating significant rate impacts for smaller communities as a result of new plant additions, particularly during the first few years of rate basing such additions. The Hamlet provided the following response:

> "Fort Providence is aware that both NWTPC as well as NUL-NWT have in the past advanced some proposals to mitigate the significant rate impacts for smaller communities arising from new plant additions. These proposals have been rejected by the Board. There are obviously many other variations to the proposals advanced in this rate application by Fort Providence. For example, the Board may want to consider:
>
> (i) Inclusion of both generation as well as distribution related capital additions
> (ii) Capping the inclusion of rate impact stemming from a new capital addition to a pre-defined maximum percentage. For example, pooling would only be appropriate up to a pre-defined maximum % variance between the zonal and average rates.
> (iii) Setting a threshold dollar amount so that only rate impacts in excess of the threshold amounts be included for pooling
>
> In Fort Providence's views, any approach must be simple to apply, be understandable, and must result in rates that are not unduly preferential or unjustly discriminatory." (BR-FP-1b)

The Board recognizes the Hamlet's concern that diesel plant additions, particularly in small diesel communities, can result in significant rate shock. The Board notes some of the rate design solutions offered by the Hamlet as noted in BR-FP-1(b) items ii and iii and considers such approaches should be considered in the future where the rate impacts are significant. In the present case, the Board does not consider the approximately 3% increase in 2006 for Fort

Providence solely as a result of the addition of new diesel generation constitutes rate shock in the context of this Application.

13.3 Burden Of Cross Subsidization

The Hamlet submitted that it bears a higher burden of cross subsidizing other diesel communities whose revenue to cost ratios do not equal 100% in 2005 and 2006.

The Hamlet stated that Hay River's burden is only about a sixth of the burden imposed on Fort Providence on a revenue requirement basis. Also, this burden for Hay River amounts to 0.131 cents per Kwh ($44,468/33,925,300 Kwh per Exhibit 2, Schedule 4.1) whereas for Fort Providence, it amounts to 1.935 cents/Kwh, ($62,595/3,233,500 Kwh per Exhibit 2, Schedule 4.1), or some 15 times higher. The Hamlet submitted it should be self-evident who has the higher burden to bear.

The Board agrees that the subsidies provided to the diesel communities, and Dory Point/Kakisa in particular, in the interest of maintaining rate stability in the subsidy receiving communities, should be borne proportionately by all subsidy-providing communities. Accordingly, the Board directs Northland to design the proposed 2005 and 2006 rates for Hay River and Fort Providence so that the entire amount of dollars required to subsidize the remaining diesel communities, after the application of the 10% rate cap to those communities, is recovered from Hay River and Fort Providence proportionate to each community's forecast of revenues in each year. The Board also directs Northland to redesign Rider J so that the subsidy reduction as a result of gradually moving the community of Dory Point/Kakisa towards revenue to cost tolerance flows to Hay River and Fort Providence in proportion to the forecast revenues in the respective communities in each of 2007, 2008 and 2009. The Board directs Northland to reflect the foregoing changes in rate design in its refiling of the Application.

14. RATE SCHEDULES

14.1 Residential and Commercial Rates

Northland stated that the existing residential Customer charge captures between 28.5% and 53% of the Customers allocated customer cost per community. Northland indicated it has not adjusted the Customer charge in the proposed rates given that it is comparable to neighbouring utilities. Northland indicated that the existing demand charge for commercial Customers has been increased to improve the recovery of the demand related costs. (BR-NUL-NWT-14d)

The intervenors did not raise any concerns respecting Northland's residential and commercial rate design. The Board will accept the proposed fixed charges for residential customers and the proposed demand charges for commercial customers for the purposes of this Decision.

14.2 Rider A

During the hearing, discussions also took place with respect to the current Rider A trigger threshold level and the Board staff requested Northland to comment on the merits of using a pooled approach from the point of view of rate stability, and identify what may be appropriate threshold levels to trigger the Rider.

Currently, changes to the Rider A rates for each community are triggered based on whether or not the change in diesel cost causes a rate impact to a residential or general service "sample customer" of greater than 2%. Northland indicated that it has considered alternate mechanisms, such as the pooled approach used by the NWTPC, but does not consider this an improvement over the existing methodology. Northland indicated that it prefers the current process for determining Rider A rates because the analysis and Riders reflect cost causation in each community, whereas a pooled approach would cause cross-subsidization of fuel costs between communities (BR-NUL-NWT-14f). Further, Northland indicated that the current process reviews the rate Riders on a quarterly basis and keeps Rider balances to a minimum.

Northland submitted that if a pooled trigger level balance was implemented by community, or if the current rate impact threshold level methodology was maintained, they could equally provide the desired rate stability provided that the trigger levels are set at an appropriate level that would reduce the number of applications for changes to the rate and thus provide more stability.

The Hamlet indicated that the existing trigger mechanism for Rider A has resulted in frequent and in some cases very significant increases (decreases) in the diesel rates of communities. The Hamlet recommended that the Board establish a reasonable dollar threshold limit before approving the collection or refund of Rider "A". The Hamlet submitted the threshold should be set at about 10% of fuel costs or $100,000 rounded up. The Hamlet also noted that mid-year balance of the deferred account will attract interest at a rate equal to the Allowance for Funds Used During Construction (AFUDC), and therefore, should provide Northland and customers adequate compensation for any balances in the diesel fuel deferral account.

The Board notes Northland's view that if the Rider A deferral account balance adjustments were triggered by a certain threshold level balance in the deferral account by community, that could provide a similar level of rate stability as under the present trigger which is based on whether or not the change in diesel cost causes a rate impact to a residential or general service "sample customer" of greater than 2%. The Board shares the concern of the Hamlet that frequent Rider A adjustments results in rate instability. The Board considers the frequent Rider A adjustments of the past may at least in part relate to the fact Northland makes spot fuel purchases. Therefore, forecasts of months ahead fuel prices may have proved difficult in past Rider A applications. However, the Board considers that Northland should take necessary steps to take into account the forecast of fuel prices looking forward for a period of at least 12 months. The issue of fuel price stability is dealt with in Section 4.1. If the forward looking forecast of fuel prices results in a change greater than 2% for a sample residential or commercial customer based on 12 month recovery, a Rider A application should be filed. The Board directs Northland to propose a Rider A mechanism that reflects the above parameters as part of the refiling of the Application.

14.3 Rider I

When the proportion of actual diesel generation in a year exceeds 2.5% of total power required to supply the Town of Hay River, Northland records the costs attributable to the excess of diesel generation over the 2.5% threshold in a deferral account and recovers this amount by way of Rider I.

The Town expressed the view that Rider I should not be used to recover diesel costs over which Northland can exercise control. The Town considered only the outages related to purchased power over which Northland had no control should be reflected in the Rider I deferral account:

> “Hay River submits that the only diesel generation costs that should be included in the Rider I deferral account should be those over which NUL has no control, i.e. outages related to NTPC hydro or transmission. NUL’s forecast outage costs which are currently incorporated into the 2.5% forecast outage rate implicit in Rider I should include 20 hours of

> generating costs per year for outages that are attributable to NUL's transmission and substations. Hay River therefore submits that future Rider I true-ups should only be applicable to NTPC related outages. In the alternative, if outages on NUL's transmission line and substations continue to be included in Rider I, there should be a downward adjustment to NUL's business risks and rate of return on equity." (Town's Argument p.4)

Northland considered the inclusion of all outages impacting diesel generation in the Rider I deferral account as appropriate. Further, Northland considered if the risks covered by Rider I are to be changed as per the Town's proposal, Northland would need to ensure that its revenue requirement included the costs of operating the Hay River plant due solely to the forecast unavailability of Northland's transmission facilities

The Board notes from HR-NUL-NWT-5 that there were a number of instances where the Hay River diesel plant operated under circumstances where Northland had control over initiating such operation. Diesel preventive maintenance run would be an example of this type of operation. In principle, the Board considers deferral accounts should be used to record amounts over which the utility has no control or where the amount cannot be forecast with reasonable accuracy. The Board agrees therefore that additional diesel generation caused by reasons that are within Northland's control should not be included in the Rider I deferral account. Based on the evidence, the Board concludes failure of hydro power supply to be the only reason for diesel operation that is outside of Northland's control. Accordingly, the Board directs Northland to not include diesel generation costs other than those directly attributable to failure of hydro power supply in the Rider I deferral account, effective January 1, 2005.

The Board notes Northland's submission that if the Board were to accept the Town's proposal, the revenue requirements should be adjusted so that the costs of operating the Hay River plant due solely to the forecast unavailability of

Northland's transmission facilities are reflected. Northland is directed to reflect this change in the refiling of the Application.

15. TERMS AND CONDITIONS OF SERVICE

15.1 Maximum Investment Levels

Northland indicated that it has not conducted any formal studies pertaining to the maximum investment levels set out in Schedule A of the terms and conditions of service for this GRA because circumstances have not changed significantly. Northland stated that during the preparation of preceding GRA’s, the Company had conducted cursory reviews of these levels and has found them reasonable at those times. Northland indicated that it will conduct a formal study to review the maximum investment levels in the future. (BR-NUL-NWT-15c)

Given that a recent formal review of maximum investment levels has not been carried out, the Board directs Northland to complete such a study and reflect the results in the next GRA.

15.2 Amendments to Terms and Conditions (T&Cs) of Service

Northland proposed an amendment clause 3.1 of the T&Cs whereby amendments to the T&Cs would take effect following notice to the Board:

> “These terms and conditions have been approved by the Board. The Company may amend these terms and conditions by filing a notice of amendment with the Board. Included in the notice to the Board shall be notification of which Customer groups are affected by the amendment and an explanation of how affected Customers will be notified of the amendments. The amendment will take effect 60 days after such notice is filed, unless the Board otherwise directs.” (Article 3.1 in part)

In the Northland YK proceedings a similar amendment was proposed by that company and the Board directed the amendment be changed as follows:

Article 3.1

These terms and conditions have been approved by the Board. The Company may amend these terms and conditions by filing a notice of amendment with the Board and interested parties from the preceding General Rate Application. Included in the notice shall be notification of which Customer groups are affected by the amendment and an explanation of how affected Customers will be notified of the amendments. The Board will either acknowledge the notice of the amendment to the Terms and Conditions or direct a further process to deal with the requested change as the Board deems appropriate. If the Board acknowledges notice of the amendment, the amendment will take effect upon the date of such acknowledgement.

Northland indicated it is not opposed to adopting the wording as directed in Decision 12-2005 for Northland YK for the re-filing. Accordingly, the Board directs Northland to reflect the revised wording of clause 3.1 in the T&Cs filed as part of the refiling Application.

16. REFILING OF THE APPLICATION

Northland is directed to refile its application in accordance with the refiling instructions in this Decision within 30 days of this Decision. Northland is directed to refile all supporting material and schedules incorporating the Board's directions together with proposed rates and riders designed to recover the 2005 and 2006 revenue requirement resulting from the Board's findings. A summary of directions related to the refiling applications are set out below:

1. The Board notes that Northland expects to correct the residential sales forecast and revenues to reflect corrected customer growth numbers in 2005 and 2006 and directs Northland to reflect this change in its refiling of the Application.

2. The Board considers in accordance with Northland's stated method of forecasting heat rates the forecast fuel efficiencies of any new engines forecast to be in service should be reflected in the forecast heat rate calculations and directs Northland to adjust the 2006 heat rate calculation for Fort Providence to reflect the addition of the new generator in 2006.

3. The Board directs Northland to use a vacancy level of 0.5 FTE in each of 2005 and 2006 and to reflect the appropriate reduction in labour, benefits and other expenses in its refiling.

4. The Board is not convinced the $27,000 cost in 2004 for regulation and Phase II activities is likely to be incurred at this level in each of 2005 and 2006. The Board considers it more reasonable to spread the costs identified

as related to regulation and Phase II over the two-year test period and directs Northland to reflect a net reduction of $13,500 for this expenditure item in each of 2005 and 2006.

5. The Board will accept the Town's proposal to reduce administration by $14,000. The Board directs Northland to reflect a net reduction of $14,000 for this item in 2005 and 2006.

6. The Board directs Northland to reduce its forecast distribution maintenance by $18,500, representing the amount indicated by Northland as catch up or deferred maintenance, in each of the years 2005 and 2006.

7. With regard to the timing of the Kakisa study, the Board agrees it is unlikely the forecast expenditure will be completed before the end of 2005 and directs Northland to move this expenditure to 2006.

8. Considering all of the circumstances including the need to bring the brushing program up to date, the Board approves transmission and distribution brushing expenditures totalling $75,000 in each of 2005 and 2006. Northland is directed to reflect this finding in its refiling.

9. The Board directs Northland to reduce the amount included for amortization of the Hay River franchise renewal to $11,000 per year.

10. The Board directs Northland to reflect the correct numbers for property taxes in revenue requirement in its refiling.

11. Northland is directed to reflect a return on equity of 9.5% for 2005 and 2006 in its refiling.

12. The Board agrees with the position advanced by the Town, namely customer deposits, net of amounts Northland forecasts to apply towards uncollectible accounts, should be included in the Company's capital structure at a cost rate reflecting the interest payable on customer deposits. The Board directs Northland to reflect this finding in its refiling.

13. Northland is directed to adjust its filing to reflect the suspension of funding to the OPEB account in 2005 and 2006.

14. The Board notes Northland's view that implementation of the new credit management system would have an impact on revenue lags. The Board considers since the cost of implementing the credit management system is included in the Application, the corresponding working capital related benefits should also be reflected in the forecasts during the test period and directs Northland to reflect the impact of the credit management system on forecast revenue lags, in its refiling.

15. The Board directs Northland to reduce the forecast for sentinel lighting to $3,000 in each of 2005 and 2006.

16. The Board considers a reduction in the Meter forecast to $6,500 in both 2005 and 2006 appropriate to reflect the average level of expenditures over the period 2001 to 2004 while recognizing some increase in costs over that same period. The Board directs Northland to reflect this finding in its refiling.

17. The Board directs Northland to propose a deferral account for capturing any benefits resulting from Rainbow type claims during the test period, along the lines approved for Northland YK in Decision 12-2005 as part of its refiling Application.

18. The Board directs Northland to design the proposed 2005 and 2006 rates for Hay River and Fort Providence so that the entire amount of dollars required to subsidize the remaining diesel communities, after the application of the 10% rate cap to those communities, is recovered from Hay River and Fort Providence proportionate to each subsidy providing community's forecast of revenues in each year.

19. The Board directs Northland to redesign Rider J so that the subsidy reduction as a result of gradually moving the community of Dory Point/Kakisa towards revenue to cost tolerance flows to Hay River and Fort Providence in proportion to the forecast revenues in the respective communities in each of 2007, 2008 and 2009. The Board also directs Northland to reflect the foregoing changes in rate design in its refiling of the Application.

20. If the forward looking forecast of fuel prices results in a change greater than 2% for a sample residential or commercial customer based on 12 month recovery, a Rider A application should be filed and the Board directs Northland to propose a Rider A mechanism that reflects the above parameters as part of the refiling of the Application.

21. The revenue requirements should be adjusted so that the costs of operating the Hay River plant due solely to the forecast unavailability of Northland's transmission facilities are reflected.

22. The Board directs Northland to refile the proposed T&Cs for approval, subject to incorporation of the change noted above with respect to Article 3.1 as part of the refiling of the Application.

17. SUMMARY OF DIRECTIONS FOR FUTURE FILINGS

The following is a summary of directions not related to the refiling applications contained in this Decision:

1. The Board directs Northland to temperature normalize historical sales for the purposes of forecasting test year sales and use normalized sales for the purposes of determining the energy balance, including line losses, at the time of the next GRA.

2. Northland is directed to provide a preliminary assessment of feasible energy supply alternatives for diesel communities, including those referred to by the Hamlet, that may help alleviate the high cost of providing electricity supply to these communities, as part of its next resource planning cycle and provide Northland's recommendations thereon to the Board and interested parties by year end 2006. Following this filing, the Board may direct that further detailed studies or a further process be undertaken or may conclude that the matter needs no further action.

3. In order to address the concerns over fluctuations in line loss percentages from years to year Northland is directed to develop procedures for determining actual line loss factors for each year, which are reasonably reflective of the electrical line losses for that year. To the extent the unbilled consumption is a factor amongst others causing fluctuations in overall loss factors from year to year, the percent loss factor applicable to electrical losses should be identified separately from the loss factor applicable to other factors under the category of unaccounted for losses. Northland should institute the

above procedures with immediate effect and explain how these procedures address the accurate determination of forecast loss factors, at the next GRA.

4. Northland is directed to provide an engineering assessment of the level of line losses in each community given the community's particular system configuration and report and reflect the outcome of the study in the next GRA.

5. The Board directs Northland to ensure the necessary brushing work is undertaken to ensure the systems safety and reliability and to provide a comprehensive status report on the state of the work as part of the next GRA.

6. The Board directs Northland to provide further evidence in relation to account 457 with additional peer comparisons together with explanations for differences, as part of its next depreciation study and/or technical update.

7. Northland is directed to address why it considers it appropriate to continue to use the accrual basis for OPEB at the next GRA given the use of the cash basis for other components of pension costs and the tax impact of accrual accounting for OPEB noted above.

8. The Board directs Northland to address the criteria for charges to the RID account at the next GRA, having regard to the criteria identified by the Hamlet in these proceedings.

9. The Board directs Northland to demonstrate the level of expenditures charged to the deferral account with respect to each type of maintenance (overhaul, top end overhaul) for the different plants are reasonable by reference to suitable benchmarks derived from other Northern utilities at the next GRA.

10. At the time of its next GRA, the Board directs Northland to provide a detailed assessment of transmission and distribution capital maintenance expenditures in excess of $5,000, indicating which, if any, of the Rainbow criteria each expenditure meets.

11. The Board considers the allocation recommended by the Hamlet is not unreasonable, should not result in significant costs, and would be of assistance in examining the income tax impacts related to this expenditure item. The Board directs Northland to provide the basis of allocation of ES&G amounts between the UCC classes in its next GRA.

12. The Board directs Northland to review all classification factors used in the cost of service study in conjunction with a similar study for Northland YK and provide the results as well as reflect the findings of the in the next GRA.

13. The Board directs Northland to not include diesel generation costs other than those directly attributable to failure of hydro power supply in the Rider I deferral account, effective January 1, 2005.

14. Given that a recent formal review of maximum investment levels has not be carried out, the Board directs Northland to complete such a study and reflect the results in the next GRA.

18. BOARD ORDER

NOW THEREFORE, IT IS ORDERED THAT:

1. Northland Utilities (NWT) Limited shall refile its 2005/2006 GRA within 30 days of this Decision in accordance with the determinations and directions contained in this Decision.

2. Nothing in this Decision and order shall bind, affect or prejudice the Board in its Consideration of any other matter or question relating to Northland Utilities (NWT) Limited.

ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES

____

DATED March 31, 2006
John E. Hill
Chairman

Northwest Territories Power Corporation, Phase 1 GRA, Decision 13-2007
August 2007

THE PUBLIC UTILITIES BOARD

OF THE

NORTHWEST TERRITORIES

DECISION 13-2007 **August 29, 2007**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northwest Territories Power Corporation for changes in the existing rates, tolls and charges for electrical energy and related services provided to its customers within the Northwest Territories.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS	Joe Acorn	Chairman
	John E. Hill	Vice-Chairman
	Gene Nikiforuk	Member
	William Koe	Member
	Sandra Jaque	Member
BOARD STAFF	Louise Larocque	Board Secretary
	Raj Retnanandan	Board Consultant
	John Donihee	Board Counsel

APPEARANCES

Stephen Lee Hugh Williamson	Counsels for Northwest Territories Power Corporation
Thomas Marriott	Counsel for the Hydro Communities
A.O. Ackroyd, Q.C.	Counsel for the Thermal Generation Communities

WITNESSES

Northwest Territories Power Corporation

Judith Goucher	Director of Finance and Chief Financial Officer
Stephen Kerr	Director of Engineering
Terence Courtoreille	Manager, Financial Planning and Coordination
John Locke	Director Information Technology and Chief Information Officer
Patrick Bowman	Consultant
Kathy McShane	Consultant

WITNESSES cont…

Hydro Communities

Lawrence Kryzanowski	Consultant

Thermal Generation Communities

Azad Merani	Consultant

ABBREVIATIONS

AECO-C	Alberta Energy Company Gas Storage Facility
AFUDC	Allowance for Funds Used During Construction
AMR	Automatic Meter Reading
ARO	Asset Retirement Obligations
BC	British Columbia
BCUC	British Columbia Utilities Commission
BR	Board Information Request
CE	Comparable Earnings
CEO	Chief Executive Officer
CICA	Canadian Institute of Chartered Accountants
CO_2	Carbon Dioxide
DCF	Discounted Cash Flow
DPC	Dogrib Power Corporation
ERP	Equity Risk Premium
FAA	*Financial Administration Act*
FMV	Fair Market Value
FSF	Fuel Stabilization Fund
FTE	Full-Time Equivalent
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse Gas
GNWT	Government of the Northwest Territories
GRA	General Rate Application
GWh	Gigawatt-Hour
HC	Hydro Communities
HDD	Heating Degree Days
HR	Human Resources
IT	Information Technology
kWh	Kilowatt-Hour
L	Liter
m^3	Cubic Meter
MERP	Market Equity Risk Premium
MWh	Megawatt-Hour
NB	New Brunswick
NCPC	Northern Canada Power Corporation
NTEC	NWT Energy Corporation

NTHC	Northwest Territories Hydro Corporation
NTPC	Northwest Territories Power Corporation
NUL	Northland Utilities
NWT	Northwest Territories
NYMEX	New York Merchantile Exchange
O&M	Operation & Maintenance
PLC	Power Line Carrier
PUA	*Public Utilities Act*
PUB	Northwest Territories Public Utilities Board
R.S.N.W.T.	Revised Statutes of the Northwest Territories
RFID	Reserve for Injuries and Damages
ROE	Return on Equity
S&P	Standard & Poors
SM	Senior Management
TCS	Terms and Conditions of Service
TGC	Thermal Generation Communities
TSX	Toronto Stock Exchange
TWU	Technical Workshop Undertaking
U.S.	United States
WCB	Worker's Compensation Board
YK	Yellowknife
Yr	Year

TABLE OF CONTENTS

1. BACKGROUND & APPLICATION

By letter dated November 24, 2006, the Northwest Territories Power Corporation ("**NTPC, the Corporation**") submitted to the Northwest Territories Public Utilities Board ("**the Board**") its Phase 1 General Rate Application ("**GRA, Application**") for the fiscal years April 1, 2006 to March 31, 2007 and April 1, 2007 to March 31, 2008 ("**Test Years**").

In its Application (Ex.2), the Corporation requested an order or orders of the Board to approve the 2006/07 and 2007/08 Revenue Requirement at $79.909 million and $84.331 million, respectively, including approval as required of the operating and maintenance expenses, amortization expenses and return on rate base. NTPC is also requesting an order or orders of the Board to approve the forecast 2006/07 and 2007/08 Rate Base, approve revised Terms and Conditions of Service, approve revised Maximum Corporation Investment levels, stabilization funds and accounting provisions.

Pursuant to the provisions of section 13.(1) of the Rules of Practice and Procedure, the Board, by letter dated November 30, 2006, directed NTPC to publish notice of the public hearing of the GRA in newspapers that circulate in the Northwest Territories. The notices published in December 2006 included details and schedule of the GRA, and invited interested persons to file a request with the Board for intervenor status (Ex.1)

By letter dated December 4, 2006, NTPC informed all communities that they had filed a GRA with the Board (Ex. 21).

NTPC, by e-mail dated December 18, 2006, advised all registered parties, that the Corporation would be holding a technical workshop on January 8, 2007 in Yellowknife.

NTPC, by e-mail dated January 9, 2007, provided all registered parties with a list of parties who attended the workshop, a copy of NTPC's presentation and a list of undertakings (Ex. 3). NTPC responded to the undertakings on January 12, 2007 (Ex. 4).

Interested parties were provided the opportunity to make request further information through information requests of NTPC and to file evidence. The requests elicited written responses from NTPC. Written evidence was filed on behalf of the City of Yellowknife and the Towns of Fort Smith and Hay River ("**Hydro Communities**" "**HC**") by letter dated February 23, 2007 and on behalf of the communities of Fort Liard, Fort Simpson and Inuvik ("**Thermal Generation Communities**" "**TGC**") by letter dated March 16, 2007. Information requests were issued by the Board and NTPC to the HC and the TGC in response to their written evidence. All written information requests by the Board and intervenors together with the responses were made available to all parties before the hearing.

The Corporation submitted a letter, dated May 16, 2007, setting out certain revisions to its GRA and supporting materials (Ex. 13).

2. PUBLIC HEARING

The hearing was held in the City of Yellowknife on May 23, 24 and 25, 2007. During the course of the hearing, members of the public who had not requested intervenor status were invited to participate in the proceeding. NTPC's panels were cross-examined by counsels for the HC and the TGC on the elements of the GRA. The TGC and HC panels were cross-examined by the counsels for the NTPC.

Board staff examined NTPC's panels and the interveners' panels with respect to a number of issues arising out of an analysis of the Application, including community specific issues. During the hearing, NTPC provided responses to a number of undertakings given at the hearing.

All parties, at the hearing, agreed to file Argument by June 18, 2007 and Reply Argument by June 29, 2007.

TGC, by letter dated June 8, 2007, requested an extension to the Reply Argument from June 29, 2007 to July 3, 2007, because their consultant was involved in another proceeding commencing the week of June 27, 2007 and attending a regulatory conference during this period. By letter dated June 13, 2007, the Board approved the requested extension to July 3, 2007.

3. RATE BASE

This section of the Decision examines the issues raised with respect to determination of the Corporation's rate base for the test years. Rate base includes gross plant in service and working capital.

3.1 Gross Plant in Service

This section of the Decision examines the issues raised with respect to determination of the mid year gross plant in service.

3.1.1 L199 Re-commissioning

The L199 transmission line experienced difficulties with respect to splices in 1996/97. The line was recommissioned in 1999 and the Corporation sought to include the costs of the recommissioning in its rate base at the 2001/03 Phase 1 GRA. At the time, NTPC was also pursuing legal claims against various parties who were involved in the initial construction of L199.

Pursuant to the 2001/2003 GRA Negotiated Settlement ("**01/03 Settlement**"), the L199 recommissioning expenses were not included in NTPC's rate base pending resolution of the outstanding legal claims. NTPC was to establish a deferral account to record the expenditures made to recommission the transmission line, which accrued interest at the rate used for the Corporation's fuel and water stabilization funds.

The 01/03 Settlement further provided that "*Following the final resolution of the existing litigation respecting the Transmission Line L199, the Corporation will apply to the Board to determine the final disposition of the balance in the deferral account*."

The total cost of the project was $3.494 million. Interest charged to the deferral account since the 01/03 Settlement totals $0.765 million. The net recoveries from the legal claims were $1.191 million ($1.605 million gross proceeds minus $0.414 million legal and related costs). Consequently, the net addition to rate base is $3.068 million.

The HC submitted customers have already paid once in rates for the construction of the L-199 line and as a result of its having failed prematurely, they are being asked to pay again for all portions of the loss not assumed by one of the parties to the lawsuit (other than NTPC) through the 01/03 Settlement.

The HC noted the difference between the reported project costs of $3.494 million and the gross proceeds of the 01/03 Settlement of $1.605 million is $1.899 million. The HC submitted pursuant to Section 49 of the *Public Utilities Act ("**PUA**")* R.S.N.W.T. 1988, c.24 (supp.), the Board is to determine a rate base based on prudent costs. The Board is not empowered to reward the utility for the financial consequences of negligent (imprudent) behavior on its part. This is true whether the imprudence is characterized as the failure to properly inspect the splices and dead ends, as alleged by the parties to the lawsuit, or a failure to ensure that there were prudent contractual arrangements with contractors including the reasonable provisions for insurance and guarantees of proper workmanship and materials that a prudent owner would require.

The HC submitted failure on the part of NTPC to be prudent in this regard, should not lead to increased rate base or increased rates for customers. In light of the fact there is no evidence that the lawsuit was not pursued vigorously, and given that the deferral account, including interest, can be interpreted as arising at the request of customers at the time of approval of the 01/03 Settlement, the HC requested a reduction to the direct or “hard costs” identified by NTPC in Chapter 6 of Exhibit 2. Accordingly, the HC submitted that the net addition to rate base of \$3.068 million requested by NTPC should be reduced by \$1.899 million, being the difference between the total cost of the project and the amount recovered in the 01/03 Settlement. (HC Argument, p. 53 – 54)

In its reply argument, NTPC submitted that there is absolutely no evidence on the record with respect to the degree or truth that NTPC’s inspection of the splices during the original construction of the transmission line was inadequate. The Corporation stated the HC called no evidence on the inspection procedures followed by prudent utilities when supervising contractors on transmission projects, nor did they request any evidence on NTPC’s own procedures in respect of this project to permit a comparison in support of their allegation. NTPC submitted the HC provided no evidence that any inspection process commensurate with industry-standard practices in 1989 (which would clearly meet any reasonable test of prudency) would have uncovered the inadequate splices. The only material filed in this proceeding that relates in any way to the inspection of splices are the unsworn Statements of Defence filed by parties that were being sued by NTPC – which parties went on to pay substantial sums to NTPC in order to settle said lawsuit. NTPC submitted it is important to recognize that the allegations made by the Defendants reflect typical defendant pleadings, and were never proven or conceded by the Corporation. Consequently, the HC have failed to rebut the presumption of prudence and the Board has no basis whatsoever on which to make a finding of fact with respect to NTPC's 1989 inspection practices in relation to the splice failures.

With respect to the prudent contractual arrangements issue raised by HC, NTPC stated its contract with MacGregor Construction Ltd is not in evidence in this proceeding. The HC did not request it be put into evidence, nor did they call any evidence in respect of the contractual terms that "a prudent owner would require" to contrast to the contents of NTPC's contract with MacGregor Construction Ltd. The Corporation submitted such evidence could have been secured, for example, by expert testimony in regards to utility contracting procedures at the time of the 1989 contract, had the HC sought to have the Board make this determination. NTPC stated the HC have failed to rebut the presumption of prudence and, absent any evidence addressing contracting standards of the day, there is no basis for the Board to make a finding on NTPC's contractual arrangements with its L199 contractors. (NTPC Reply, p.38)

The NTPC submitted that the HC Argument is entirely premised on the fact that the Corporation agreed to settle the case for $1.605 million, rather than proceed to trial to pursue full recovery of the recommissioning costs; consequently, the HC conclude that a full finding of fault on the part of the defendants (and not on NTPC) is unavailable and further suggest that as a result, NTPC should be viewed to be partially at fault for the failures. NTPC stated this conclusion is incorrect and not appropriate. NTPC stated the reasons for its decision to accept the settlement, and not to proceed to trial, include the costs of a lengthy trial (which may not be all recovered even if the Corporation won at trial), the evidentiary difficulties stemming from the fact that the construction project was completed nearly 20 years ago and many of the parties to the project were no longer available, as well as substantial concerns over the ability of certain defendants to be able to satisfy any significant judgment against them. The

Corporation submitted a concern about a potential finding of fault did not factor into the Corporation's decision to settle the lawsuit. The Corporation submitted further that the decision of a plaintiff to accept a substantial sum of money in settlement of its lawsuit does not reflect an admission of negligence or even partial negligence on its part and any insinuation to this conclusion is wholly inappropriate.

Views of the Board

The Board is of the view that any disallowance of costs must arise from clear evidence that the Corporation was negligent in its actions with respect to the L199 repair project or that the management of the project or the lawsuit was in some other way imprudent. Based on the evidence in this proceeding, the Board finds that there is not sufficient evidence to arrive at a finding the Corporation was negligent, nor is there other evidence of poor management in respect of the L199 project or of a lack of prudence on the Corporation's part. Accordingly, the Board will allow the Corporation to include the $3.068 million cost of the L199 transmission repair in rate base for the 2005/06 fiscal year.

The Board expects NTPC, in its dealings with contractors, to establish prudent contractual arrangements including the reasonable provisions for insurance and guarantees of proper workmanship and materials that a prudent owner would require.

3.1.2 Fort McPherson Power Plant

The Corporation included the following rate base additions in 2004/05 and 2005/06 with respect to a plant rebuild and other improvements resulting from a fire in the community of Fort McPherson:

	2004/05	2005/06	Total
	$000	$000	$000
Diesel power plant additions	7336	660	7996
Insurance proceeds	-5085	0	-5085
Net Additions	2251	660	2911

NTPC indicated the $2.911 million net additions to rate base consisted of betterments amounting to $1.896 million as well as $820,000 for capitalized overhead expenses not covered by insurance and $193,000 deductible on the plant rebuild. (BR.NTPC-27)

The TGC submitted there is very little evidence on the significant difference between the forecast replacement costs ($5.5 to 7.0 million) and the actual cost to rebuild of $9.816 million. Given the sheer magnitude of the cost of the re-build, and the extent of cost overruns, the onus is on NTPC to demonstrate its costs were reasonably and prudently incurred. The TGC considered the Corporation might have incurred higher costs with respect to the project as a result of having to complete the project within a time frame stipulated by the insurance underwriter. TGC submitted there should be at least a 10% disallowance of costs incurred to re-build the Fort McPherson plant for the above reasons. (TGC Argument, p. 44)

NTPC indicated there is no evidence to suggest the Corporation incurred additional costs due to the requirement to complete the work within a stipulated timeframe. (NTPC Reply, p. 35)

Views of the Board

The Board notes the actual cost of plant rebuild excluding betterment costs is $6.1 million [$7.996 million total plant costs minus betterment costs of $1.896 million]. The Corporation recovered $5.085 million of the plant rebuild costs from insurance proceeds.

The Board notes from the response to TGC.NTPC-55(b) that the Corporation charged an amount of $315,000 to the reserve for injuries and damages ("**RFID**") in 2005/06 with respect to the Fort McPherson plant fire repair deductible and items not covered by insurance. Given that the plant fire repair deductible is already included as a charge against the RFID in 2005/06, the Board does not find NTPC's explanation in BR.NTPC-27 that the deductible on plant rebuild in the sum of $193,000 included again as a component of the plant rebuild costs, to be a credible explanation of the costs comprising the net capital additions in relation to the Fort McPherson plant. Accordingly, the Board directs NTPC, as part of its refiling, to reduce the opening plant balance for 2006/07 by $193,000 being that portion of the rate base addition for the Fort McPherson plant that has not been explained nor demonstrated to be a prudent expenditure by NTPC.

3.1.3 Bluefish Generating Station

NTPC added the Bluefish generating station to rate base in 2004/05. The purchase price plus the cost of capital works amounts to $12.603 million. In support of the Bluefish addition to rate base, NTPC stated as follows:

> "In response to BR.NTPC-9, the Corporation noted that at the time of the purchase, the Bluefish purchase was estimated to have a positive impact for ratepayers with a net-present value of $38.1 million. Since that time, the economics of the purchase have been affected by a number of factors,

> most notably increases in the price of diesel fuel, offset by actual and forecast capital improvement costs that are higher than was anticipated at the time of the Bluefish purchase. As a result of these factor, an updated project economic assessment was presented in BR.NTPC-9, which indicates that the net present value benefit to ratepayers is now expected to be $51.4 million (2005$) – an increase of 35 per cent from the forecast at the time of the project permit application.
>
> In summary, the Bluefish project was a prudent acquisition that is providing benefits to customers today and will continue to provide benefits into the future. No intervenor submitted evidence to suggest that the costs of the project were not reasonable. The Corporation submits that the project should be approved as part of the rate base for the test years." (NTPC Argument, p. 48, *ll*. 8 - 20)

Views of the Board

The Board considers the purchase of the Bluefish hydro plant to be prudent and approves the inclusion of the plant in rate base in 2004/05.

3.1.4 Snare Rapids Plant Upgrade

NTPC added $3.838 million in 2005/06 and proposed the addition of $1.305 million in 2007/08 to rate base with respect to the Snare Rapids plant upgrade. In support of the Snare upgrade additions to rate base, NTPC stated as follows:

> "The Snare Rapids Plant upgrade was reviewed and approved by the Board in Decision 8-2004. The project permit application included NTPC's proposed budget of $4.984 million, which was specifically noted as being a "budget level" estimate and not an "engineering pre-design" estimate. The GRA forecast costs are $0.159 million higher and include capital costs of $3.838 million in 2005/06 and forecast costs of $1.305 million in 2007/08 for total project capital costs by the end of the test period of $5.143 million. A breakdown of the costs included in the $3.838 million portion of the project was provided in response to HC.NTPC-60(a).

> The Corporation submits that the project costs included in the test period are reasonable and should be approved." (NTPC Argument, p. 49, *ll*. 15 - 23)

Views of the Board

The Board notes none of the interested parties raised any concerns respecting the Snare upgrade additions. The Board considers the Snare Rapids plant upgrade additions to be prudent and approves the inclusion of the plant in rate base as proposed.

3.1.5 Aklavik Power Plant

NTPC proposed the addition of $5.298 million with respect to a new modular power plant in Aklavik to rate base in 2007/08. NTPC indicated the existing plant was originally built in 1976. Since that time, the community has developed in the area around the plant. With this increased development, there have been complaints from local residents related to plant noise and air emissions. As a result, the Corporation indicated it has received support from the Aklavik Council to relocate and build a new modular power plant outside the town property.

The project permit for the modular power plant at Aklavik was approved at $4.9 million in Decision 11-2006. The Board notes the forecast costs are higher than the project permit estimate by $398,000 or about 8%. The Board also notes the project cost estimate was increased from $3.5 million to $4.9 million at the time the project permit application was submitted to the Board. At that time, NTPC indicated the increased costs are attributable partly to delays from the original schedule due to ongoing consultations with the community and due to deployment of the Corporation's engineering staff to address the fire at Fort

McPherson. (Decision 11-2006; p. 4) The Board notes that although the project permit application contemplated addition of the unit to rate base in 2006/07, the Corporation is now proposing to add the plant to rate base in 2007/08.

Views of the Board

The Board is concerned by the significant cost overruns noted at the time of the project permit application and the additional adverse cost variance between the project permit amount and the forecast addition for 2007/08. The Board considers some of the cost increases resulted from unforeseen circumstances, which resulted in delays in the completion of the unit, and the Board is not convinced the customers of Aklavik should bear the entire cost risk resulting from these delays. Accordingly, the Board considers the carrying costs and overheads associated with delays due to unforeseen community consultations and deployment of the Corporation's engineering staff to address the fire at Fort McPherson should be shared between the Corporation's shareholder and the customers of Aklavik.

The Board directs NTPC, in its Phase 1 refiling, to reduce the cost of the Aklavik plant addition by 50% of the cost increase resulting from the delays. The costs to be included for the 50% risk sharing adjustment are overheads and Allowance for Funds Used During Construction ("**AFUDC**") resulting solely from the delays in completion of the plant caused by the unforeseen length of time spent on community consultations and the fire at Fort McPherson.

3.2 Fort Liard Distribution Upgrade

NTPC proposed to add $900,000 to rate base in 2007/08 in the community of Fort Liard. NTPC indicated this project consists of upgrading the plant voltage from 600 volts to 4,160 volts. This increase in voltage capacity is required to meet any future load growth that may occur due to increased oil and gas activity in the area.

TGC argued that since this project is not expected to go ahead during the 2007/08 test year, the corresponding costs should be removed from rate base:

> “However, in Response TGC.NTPC-58, NTPC indicated there was uncertainty as to when the expected growth in oil and gas activity would materialize; further, at hearing, NTPC confirmed this project is not anticipated to proceed.
>
> Based on the foregoing, the TGC submit this project, with a forecast cost of $900,000 in 2007/08 should be removed from rate base. It is not clear what load growth is exactly included in the 2007/07 forecast for Fort Liard; obviously, if the capital project is removed, the TGC expect any associated load forecast should be removed as well, and NTPC should be directed to provide this information.” (TGC Argument, p. 24)

NTPC submitted it is not appropriate to recognize this one change in the capital forecast without regard to offsetting other projects.

> “…TGC argues for removal of this one project to reflect actuals despite having sought no evidence at any time in regards to the dynamic changes in the capital plan, the reprioritization that has occurred during the year and the offsetting other projects that have been changed or added to the plan on an actual basis that were not forecast.
>
> Under a future forward test year regulatory framework, the utility’s forecasts leading forward from the date of filing are the appropriate basis for developing and testing the revenue requirement. To the extent they are

> available, some actual results can aid in the testing of the reasonableness of the forecasts, but it is simply not appropriate to substitute those actuals for the utility's forecast. Were that to be the case, the form of regulation would be more akin to retrospective regulation with an assured earning of a fair net income and return, which is not the regulatory framework in NWT or any other Canadian jurisdiction." (NTPC Reply, p.3. *ll*. 7 - 17)

Views of the Board

The Board notes the Corporation appears to have recognized the forecast sales based on which the plant upgrade was predicated would not materialize at the time of the filing of the Application.

> "NTPC has forecast the load to reflect the latest information at the time of filing concerning the impact of oil and gas activity which is lower than when this project was first identified." (TGC.NTPC-58(c))

The Board is of the view that it was likely that the Corporation would have known the project would not proceed at the time of the filing of the GRA. Therefore in order to be consistent with the determination of the sales forecast, the Corporation's forecast plant upgrade should also be excluded from rate base additions in 2007/08. The Board directs NTPC, in its refiling, to exclude the capital addition related to the plant upgrade amounting to $900,000 from rate base additions for Fort Liard in 2007/08.

3.3 Working Capital

The Corporation's calculation of necessary working capital for the test years is set out in Schedules 5.8 and 5.9 of the Application. One of the components of working capital is the allowance of cash working capital. The purpose of allowing cash working capital is to recognize the time lag that occurs between when payments for expenses are made and when the corresponding revenues are received. The cash working capital was estimated on the basis of a lead lag study carried out by the Corporation.

The TGC expressed concern that the revenue lag days in the lead lag study were unduly high because they were estimated on the basis of the maximum time allowed for payment of bills before penalties are imposed:

> "The TGC submit NTPC's assumption all customers pay on the "maximum allowable time for payment prior to interest charges" may be over-stating the revenue lags to the extent customers pay their bills prior to the date interest charges commence. To this end, the Board should direct NTPC to incorporate, in its next GRA, a proper sampling of bill payments from various sources (industrial, wholesale, NWT Housing Association, Territorial Subsidy and Domestic/Commercial/Street Lighting) in order to properly assess the actual number of days it takes on average for customers to pay bills. To the extent payments received after the due date attract interest and/or late payment penalties, the Corporation should also address why such payments should be included in this sample for purposes of conducting the lag associated with revenue collection." (TGC Argument, p. 48)

The TGC also expressed concern that the expense items comprising the cash working capital do not reflect the corresponding net lag days associated with that expense item. TGC submitted the Board should direct NTPC, in its refiling, to provide a computation of its cash working capital for the Test Years using the net lead or lag associated with each expense item.

Views of the Board

The Board agrees with TGC that the use of the maximum number of days before penalties are imposed to estimate the revenue lag is unrealistic. Accordingly, the Board directs the Corporation to estimate the revenue lag based on sampling the number of days it takes for recovery of revenues, on average, from customers, for the next GRA.

The Board also agrees with TGC that each item of expense in the cash working capital calculation should reflect its corresponding lead or lag. This is to recognize the changes in the relative proportions of expenses included in the cash working capital calculation from year to year. Accordingly, the Board directs NTPC to provide, in its refiling, a computation of its cash working capital for the Test Years using the net lead or lag associated with each expense item.

4. RETURN ON RATE BASE

4.1 Cost of Debt

NTPC calculated the effective cost of long-term debt using the following formula:

Effective Cost of Long Term Debt= (I+AFC-SFE)/(DWAD-UFC-SFI)

Where:
I= Interest on Daily Weighted Average Long Term Debt
AFC= Amortization of Financing Costs
SFE=Sinking Fund Earnings in the year
DWAD=Daily Weighted Average Debt Principal
UFC=Unamortized Financing Costs
SFI=Sinking Fund Investment

The resulting debt rates proposed by NTPC for the two test years are as follows:

2006/07	10.532%
2007/08	10.927%

The calculation of the effective cost of long-term debt is provided in Schedule SM 3 of Exhibit 3 from the Technical Workshop. NTPC also provided a detailed continuity schedule of the sinking fund balance for each of the sinking fund debt instruments in Exhibit 4 Table NTPC.TWU-15. Further details respecting sinking fund investment terms were provided in HC.NTPC-23.

The HC in its filed evidence disagreed with NTPC's proposal to include sinking fund earnings and the sinking fund investment as part of the effective cost of long-term debt calculation. HC expressed the view the sinking fund earnings as well as the sinking fund balance should be excluded from the calculation of the effective cost of long-term debt.

> “Our recommendation is that the Board adopt the method of calculation prescribed by the Board in Alberta for this purpose, which considers no sinking fund earnings in the calculation. Further, we recommend that the resulting embedded cost of debt be used by NTPC for all its calculations, including but not restricted to AFUDC, working capital and capital lease. We recommend the method prescribed by the Board in Alberta because of the inequities in the current formula used by NTPC to calculate the cost of debt with sinking funds that are due to the formula’s construction and because the costs that are generated from the current formula explode as the debentures approach maturity. …” (Ex.8, p, 107)

The HC also recommended the Board consider some cost sharing with respect to certain sinking fund debentures, namely, the $20 million debenture issued in March 1989 with a coupon of 11%, the $15 million debenture issued in June 1991 with a coupon of 11.125% and the $20 million issued in March 1992 with a coupon of 10.75%. HC indicated cost sharing with the shareholder would be appropriate since these debentures did not include a call feature and the Corporation’s sinking funds investment policy prior to the proclamation of Bill 9 which permitted more diversified investments in the sinking fund, did not conform to best practice.

> “Yes, we would recommend that the Board consider some cost sharing between the rate payers and shareholders of NTPC that recognizes the ongoing excessive costs associated with the three earlier debentures with sinking funds and with earlier management of the investment policy of the sinking fund in addition to our recommendations at page 107. The reason for the former is that these debentures did not conform to “best practice” because they did not include a call feature, and the reason for the latter is that the earlier investment policy did not conform to the principles of “prudent portfolio” management because the portfolio of investments was not well diversified and could have achieved a higher return with about the same risk.” (Ex.8, p.108)

The HC submitted that it is appropriate to examine the terms of the sinking fund issues in this proceeding since the Corporation did not specifically request the current sinking fund treatment until the 2001/02/03 GRA and then it was implicitly approved as part of a 01/03 Settlement.

> "NTPC implies that each of the sinking fund issues was subject to Board review and approval, and from that perspective, it would be unfair to revisit the terms and conditions of bonds that were issued up to 17 years ago. It should be noted that while the Board approves the purposes of the bond or debenture at the time of issue, it typically defers approval of the specific terms and conditions, and in this case the regulatory treatment of debentures with sinking fund provisions, to the next GRA. NTPC did not specifically request the current sinking fund treatment until the 2001/02/03 GRA and then it was implicitly approved as part of a negotiated settlement." (HC Reply, p.10)

The HC also argued that, since NWT Energy Corporation (a more risky non-regulated entity) could issue debentures without sinking funds, NTPC could have issued debentures either without sinking funds or with less onerous sinking fund provisions. (HC Reply, p.9)

NTPC stated that the effective cost of long term debt formula recommended by the HC would put the utility's return on equity at risk, a risk for which the utility has never been compensated.

With regard to the effective cost of long term debt calculations where sinking fund investments are involved, NTPC indicated its proposed calculation is consistent with that used in four other jurisdictions.

> "…There are four jurisdictions in Canada (other than the Northwest Territories) with Crown utilities regulated on a rate base/rate of return basis and whose capital structures include sinking fund debt (with offsetting sinking fund assets). The utilities and the jurisdictions are: BC Hydro (British Columbia Utilities Commission), NB Power Transmission

> Corporation (New Brunswick Board of Commissioners of Public Utilities), Hydro Québec Distribution and TransÉnergie (Régie de l'Énergie de Québec), and Newfoundland and Labrador Hydro (Newfoundland and Labrador Board of Commissioners of Public Utilities). All four of these utilities calculate their embedded cost of debt using the same methodology as NTPC. In three of these jurisdictions (British Columbia, Québec, and Newfoundland and Labrador), the propriety of the embedded cost of debt calculation has not been questioned. In New Brunswick, the methodology was explicitly reviewed by the regulator in 2003 and found to be appropriate." (Ex.12 McShane Rebuttal, p.10 – 11, *ll*. 289 - 302)

With regard to the inequities referred to by HC concerning the debt rate formula, NTPC stated the calculated rate is primarily a function of the fact that (1) the specific debt issue is very close to maturity and thus the amount of the net proceeds (the denominator of the formula) is very small since the sinking fund was virtually fully funded in 2005/2006; (2) the projected earnings on the related sinking fund reflect the fact that the issue is to be retired shortly and thus the related investments have been immunized, i.e., their duration is similar to the remaining term to maturity of the debt; and (3) interest rates happen to be at a relatively low level at present compared to 1989 when the 11.0% issue was made. (Ex.12 McShane Evidence, p.7)

With regard to the prudence of the terms under which the three debentures referred to above were issued, the Corporation stated at the time the sinking fund debentures were issued (1989-1998), NTPC was a virtually unknown quantity from a creditworthiness perspective, and was issuing relatively small amounts of debt, and thus there would have been very few potential investors for NTPC's long-term debt. While its debt carried a guarantee from the Government of the Northwest Territories, neither NTPC nor the government itself had a credit rating.

With regard to HC's view that the Corporation failed to follow best practice in the management of the sinking fund, NTPC indicated the investments allowed under the *Financial Administration Act* ("***FAA***") prior to Bill 9 were substantively the same as those in which the sinking funds of other government-owned electric utilities continue to be invested. None of these entities invest the sinking funds designed to retire debt securities in equities, as NTPC has been permitted to do under the provisions of Bill 9.

Views of the Board

The Board considers sinking fund investments, together with earnings on such investments, are put in place in order provide some or all of the cash flow required to retire the corresponding sinking fund debt when it becomes due for payment. The funds transferred to the sinking fund are no longer available to the Corporation since they are set aside specifically for the purpose of retiring the debt. Therefore, to the extent earnings on sinking fund investments do not match the corresponding debt rate there is either a cost or benefit to the Corporation as a result of the investment in the sinking fund until such time as the sinking fund debt instrument is retired.

The Board notes the average sinking fund debt rate exceeds the average sinking fund return by about 6% in each of the two test years as shown below.

		Debt Interest Rate Vs Sinking Fund Return				
		$000				
		Debt Principal		Sinking Fund Investment		
		Mid Yr 06/07	Mid Yr 07/08	Mid Yr 06/07	Mid Yr 07/08	
1	11% Debt Mar 9/89	11.000%	20000	20000	19191	20830
2	11.126% debt Jun 6/91	11.125%	15000	15000	9087	10199
3	10.750% Debt May 28/92	10.750%	20000	20000	10434	11880
4	8.700% Debt Feb 27/96	8.410%	8700	8700	261	446
5	6.330% Debt Oct 27/98	6.330%	10000	10000	1150	1504
6	Total		73700	73700	40122	44858
			Debt Interest		Sinking Fund Earnings	
7	11% Debt Mar 9/89		2200	2200	553.00	602.00
8	11.126% debt Jun 6/91		1669	1669	453.00	507.00
9	10.750% Debt May 28/92		2150	2150	524.00	594.00
10	8.700% Debt Feb 27/96		732	732	12.00	21.00
11	6.330% Debt Oct 27/98		633	633	50.00	67.00
12	Total		7383	7383	1592	1791
13	Average Interest Rate/Sinking Fund Return		10.018%	10.018%	3.968%	3.993%
14	Difference between debt rate and sinking fund return				6.050%	6.026%
15	Carrying cost of sinking fund investments [L6*L14]				2427	2703

As shown in the above table, the difference between the average debt interest rate and the sinking fund return times the sinking fund balance constitutes the carrying cost to the Corporation of the sinking fund investments. This cost could also be a benefit if the earnings on sinking fund investments exceed the average debt rate in any given year. The Board notes the Corporation's proposed formula is designed to reflect the carrying cost of sinking fund investments in the effective cost of long-term debt for the two test years. On the other hand, the effective cost of debt formula recommended by HC does not recognize the carrying cost of sinking fund investments since it ignores both sinking fund earnings and sinking fund investments in the debt rate formula.

The terms of sinking fund investments are governed by the corresponding debt covenants. In the Board's view, the carrying costs associated with sinking fund investments are part of the cost of borrowing under a sinking fund debt instrument. Therefore the Board finds it appropriate to provide for recovery of sinking fund carrying costs or benefits, as the case may be, in the effective cost of debt formula.

Notwithstanding the above finding, the Board observes that instability in the effective cost of debt can be caused by variations in sinking fund returns from year to year. The annual average sinking fund investment returns for NTPC are shown in the following table:

Average Sinking Fund Earnings %	
2003	6.17
2004	6.52
2005	5.52
2006	9.72
2007	3.97
2008	3.99
Average	5.98

Note: 2003-06 from X8; P104

The Board notes the relatively low sinking funds returns in 2006/07 and 2007/08 are partly the result of immunizing the investments associated with the $20 million debenture debt issued in March 1989, in anticipation of the retirement of the debt in March 2009. These relatively low sinking fund returns have the effect of increasing the effective cost of long-term debt in the two test years.

The Board considers a normalized sinking fund return based on the average returns over the 6 year period shown above, rather than each test year's forecast return, would provide for stability in the effective cost of long term debt from year to year. The Board also notes from the term sheets for the $20 million 8.41% debenture debt issued February 1996 and the $10 million 6.33% debenture debt issued October 1998, that the expectation for the long term average return on sinking fund investments associated with these two debentures is 6%. The Board considers therefore that a 6% return reflects a reasonable estimate of expected and realized long-term average returns on sinking fund investments and would provide for a more stable effective cost of long-term debt calculation over time. Further the Board considers basing the sinking fund return on a long term average sinking fund return would avoid potential windfall gains or losses to the Corporation which could be the case if the sinking fund returns were based on specific test year forecasts. Accordingly, for the purposes of these proceedings, the Board directs NTPC to use a 6% sinking fund return for each of the test years for purposes of calculating the effective cost of long-term debt.

The Board notes the HC's argument that this is the first time the treatment of debt costs including sinking funds is being proposed by NTPC in the context of a proceeding other than the 01/03 Settlement and therefore it is appropriate to review the terms of the sinking fund debenture issues although they were issued several years ago. However, the Board considers the prudence of the terms of each issue should be examined based on evidence surrounding the specific circumstances of each issue. Given the passage of time since the debenture issues were made, the Board considers the evidence before it is insufficient to assess what the potential impacts on debenture debt rates would have been, had they been issued with call features and/or without sinking fund provisions and/or with less stringent sinking fund requirements. Therefore, the Board is not persuaded by the HC's recommendations that there should be a risk sharing adjustment on certain sinking fund debentures or that the terms of certain debenture issues including the sinking fund provisions should be re-examined in these proceedings.

In addition to the sinking fund treatment, the Board notes NTPC has calculated the debt interest and debt balance on a daily weighted average basis. Since the mid year convention is used for determining the rate base, the Board considers the debt balance and debt interest should also be calculated on a mid year basis in order to be consistent.

The Board, therefore, directs the Corporation to calculate its effective cost of long term debt as follows in its refiling:

Effective Cost of Long Term Debt= (I+AFC-SFE)/(MAD-UFC-SFI)

Where:
I= Interest on Mid Year Average Long Term Debt
AFC= Amortization of Financing Costs
SFE=Sinking Fund Earnings in the year based on long term averge return of 6%
MAD=Mid Year Average Debt Principal
UFC=Unamortized Financing Costs
SFI=Sinking Fund Investment

4.2 Capital Lease

NTPC proposed a cost rate for the Snare Cascades capital lease of 9.69% in 2006/07 and 9.70% in 2007/08. NTPC indicated the capital costs that the Corporation incurs with respect to the lease represent the Dogrib Power Corporation's ("**DPC**") costs of financing comprised of DPC's cost of debt raised to finance the construction of the project (9.6% on 93.26% of DPC's capital structure) and a return on DPC's equity position in the project (NTPC's allowed return on equity less 0.25% on 6.74% of DPC's capital structure).

DPC's cost of debt financing, in turn, reflects the actual cost rate of borrowing from NWT Energy Corporation an amount of $22.9 million under a loan agreement between the two parties. To provide the debt financing to DPC, NWT Energy Corporation issued three series of debentures as follows:

Date of Issue	Amount of Issue	Due Date	Coupon Rate
May-95	$8 million	May-25	10.00%
Oct-95	$8 million	Oct-25	9.75%
Sep-96	$9 Million	Sep-26	9.11%

The weighted average cost of the debt that was issued by NWT Energy and loaned to DPC was 9.6%. The 9.6% average cost of debt incurred by DPC is the same 9.6% rate that is included in the calculation of the capital cost of the lease that is part of NTPC's revenue requirement.

The $22.9 million loan is being amortized and repaid by DPC to NWT Energy Corporation in monthly installments of $195,068 over a period of 30 years.

The HC expressed the view the NTPC could have borrowed at a lower rate than its unregulated subsidiary NWT Energy Corporation at the point in time the lease arrangement was entered into. This would have lowered the cost of the loan to the DPC. In turn, this would have lowered the cost of the lease to the NTPC. HC's expert witness noted that NTPC's calculation uses weights of 6.74% equity and 93.26% debt while the standard approach is to employ a debt weight of 100%. Further, the HC expert witness noted that if the cost of the lease is to include an equity component then the cost of equity should be lowered by more than 25 basis points to capture the lower risk of the lease. (Ex.8, p. 110 - 111; HC Reply, p.13)

NTPC submitted reviewing the terms of the DPC agreement 10 years after it was entered into would constitute retroactive ratemaking.

> "…As stated in Board Decision 1-97 (January 14, 1997), the Board "examined the evidence before it and agrees with the parties that the above interest rates are reasonable for this portion of the capital structure.

> The Board approves lease interest rates of 10.063% and 10.044% for the Test Years 1996/97 and 1997/98 respectively." In my view, a retrospective reconsideration of the prudency of the capital lease arrangement entered into by NTPC more than 10 years ago constitutes retroactive ratemaking." (Ex.12 McShane Rebuttal, p.22, *ll*. 614 - 620)

NTPC indicated the cost of borrowing on the debt issued by NWT Energy Corporation to finance the loan to DPC is consistent with borrowing costs on B++ debenture debt at the time of issue.

> "Nevertheless, a comparison of the yields on the NWT Energy debentures to yields prevailing on outstanding long-term B++ rated Canadian utility bonds at the time the NWT Energy debt issues were made and the funds were loaned to DPC provides a clear indication that the cost of the debt component of the capital lease was reasonable." (Ex.12 McShane Rebuttal, p.22, *ll*. 622 - 626)

NTPC noted that in the event of a disallowance of the capital lease costs, the power acquisition agreement between DPC and the Corporation provides that DPC will pay to the Corporation the amount of the disallowed costs.

> "Were the Board to adopt the recommendations of Drs. Kryzanowski and Roberts, it is important to note the impacts that would arise. The Power Acquisition Agreement between the DPC and NTPC provides that the DPC will pay to NTPC the amount of all Disallowed Costs. Under that agreement, "Disallowed Costs" means amounts payable by NTPC under the agreement which the Board does not permit NTPC to recover in its rates, tolls and charges. The lease was structured to ensure that regulatory risk for recovery of the costs of the project from ratepayers was a risk that DPC bore, not NTPC. Ultimately, it is DPC that would be directly and adversely impacted were the Board to accept HC's recommendations. …" (Ex.12 NTPC Rebuttal, p.3, *ll*. 31 - 37)

In its reply argument, the HC submitted that the DPC capital lease arrangements were a three part commercial arrangement and all parties were aware of the contractual risks associated with strict application of their commercial arrangement.

> "…Furthermore, this is a three-way commercial arrangement that involved two interrelated entities (NTPC and NTEC), as well as two nonregulated parties (NTEC and DPC), and where all parties supposedly were aware of the contractual risks associated with the strict application of their commercial arrangement. Thus, Drs. Kryzanowski and Roberts do not recommend any changes to the commercial agreement between NTPC, NTEC and Dogrib nor do they recommend that the terms of that agreement be violated." (HC Reply, p.13)

Views of the Board

The Board considers the time for raising issues concerning the prudence of the DPC lease financing rate was the 1996/97/98 GRA when the inclusion of the DPC hydro plant in rate base and the related financing arrangements were examined and agreed to by interested parties. The Board does not consider a retrospective review of the long-term debt rate or the cost structure of the lease financing arrangement, approved in a previous proceeding, to be conducive to maintaining a climate of regulatory certainty in the NWT. Therefore, the Board does not accept the HC's recommendation that the debt financing rate reflected in the DPC capital lease be reviewed and reset.

The Board directs NTPC to include a capital lease rate that reflects, for the equity portion of lease financing, the equity rate of return approved by the Board in this Decision less 25 basis points, in its refiling application.

The Board notes the value of the annual lease payments to DPC over the 65 years is financially equivalent to DPC's cost of capital. The lease payments by NTPC to DPC include depreciation based on a 65-year amortization of the lease and carrying costs on the unamortized balance of the lease reflecting 93.26% debt at 9.6% interest and 6.74% equity at the allowed rate of return on equity minus 25 basis points. DPC's cost of financing the lease, on the other hand, is based on 93.26% debt owed to NWT Energy at 9.6% interest which is being repaid over 30 years and 6.74% equity at the allowed rate of return on equity minus 25 basis points. Since the 9.6% debt to NWT Energy is being repaid by DPC over 30 years, the cash flow profile of the lease payments by NTPC to DPC differs from the cash flow profile of DPC's debt repayments to NWT Energy. Given this mismatch in cash flow profiles, the Board considers there may be potential for DPC to reduce its cost of capital by substituting some of the higher cost debt included in its capital structure with lower cost debt as the 9.6% debt is being amortized over 30 years. The Board directs NTPC to address the potential for better matching the carrying cost of the lease to DPC with the cost of the lease to NTPC over the 65-year term of the lease, at the next GRA.

4.3 Capital Structure

The NTPC proposed capital structure for the two test years is as follows:

	2006/07	2007/08
Common Equity	45.53%	48.59%
Long Term Debt	44.53%	41.65%
Capital Lease Obligation	10.86%	10.61%
No Cost Capital	-0.92%	-0.85%
	100.00%	100.00%

The above capital structures reflect the Corporation's forecast capital structures, as opposed to deemed capital structures, in each of the test years.

In support of the proposed capital structure, Ms. McShane, expert witness for NTPC, stated NTPC would need a more conservative capital structure compared with a typical investor owned utility, in order to achieve a similar debt rating in light of its small size, higher business risks and non taxable status. Ms. McShane stated that in her opinion, a common equity ratio in the range of 45-50% would be adequate to allow NTPC to achieve a BBB rating on a stand-alone basis and NTPC's actual equity ratios are forecast to be in that range. Ms. McShane defined a benchmark utility as an A-rated utility and indicated NTPC's risk would remain higher than that of the benchmark which would suggest an incremental equity risk premium is required for NTPC. (Ex 12; McShane Evidence, p.18)

Among the business risks the utility is exposed to, Ms. McShane discussed market risks, supply and physical risks as well as regulatory risks.

With respect to market risks Ms. McShane stated the reliance on a small number of cyclical industries with a sparse population results in a higher level of market risk.

> "…While the outlook is one of strong growth in the near to medium term, the reliance of the NWT on a small number of cyclical industries, in conjunction with the sparse population, results in a higher level of market risk for NTPC relative to the typical Canadian utility which operates in a more diverse economic environment with higher population density." (Ex. 2, Appendix B, McShane Evidence, p. 12, *ll*. 323 - 327)

Ms. McShane indicated NTPC faces an inherently higher level of risk relative to other integrated Canadian electric utilities with respect to supply and physical risks.

> "With respect to supply and physical risks, NTPC faces an inherently higher level of risk relative to other integrated Canadian electrical utilities. The level of risk is in large part a function of the severe climate, the vast geographic expanse and rugged terrain of the service area, and the lack of a system grid to connect the communities served." (Ex.2, Appendix B, McShane Evidence, p.12, *ll*. 329 - 333)

Ms. McShane indicated the regulatory environment in the NWT has been even-handed in its approach and the use of rate stabilization funds mitigates risks.

> "With respect to regulatory risk, the regulatory environment in the NWT has been even-handed in its approach. The authorization and maintenance of the rate stabilization funds, which mitigate risks beyond the control of the utility, are an indication of that even-handedness." (Ex.2, Appendix B, McShane Evidence, p.13, *ll*. 354 - 357)

With regard to financial risks, Ms. McShane indicated in comparison to the interest coverage ratios of the major Canadian electric utilities, NTPC's 2003/2004 to 2005/2006 average of 1.7 times interest coverage ratio has been considerably weaker. The average (pre-tax) interest coverage for the major Canadian electric utilities with rated debt over the same period was 2.5 times. She indicated a key reason for the difference is the taxability of the major Canadian utilities because the income tax allowance provides a cushion that enhances interest coverage ratios.

Drs. Kryzanowski and Roberts, expert witnesses for the HC, recommended a deemed equity ratio of 42% for the two test years. The HC summarized the expert witnesses view with respect to business risk as follows:

> "In summary, NTPC's business risk is at an acceptable level with regard to the major factors causing business risk for a regulated electric utility in Canada. Drs. Kryzanowski and Roberts base this assessment on their view that the regulatory process and prudent management practices will combine to mitigate the potential risks discussed in their evidence. Two further favorable factors are the lack of competition and reliance on hydro generation which shields the company from the risk of rising energy prices. On the other side of the ledger, NTPC is smaller than the sample companies investigated by Drs. Kryzanowski and Roberts and faces challenges due to the geography of its service area. On balance, the Hydro Communities' view is that the business risk faced by NTPC is somewhat higher than that faced by the average integrated electric company or the average utility in Canada. …" (HC Argument, p. 42)

Drs. Kryzanowski and Roberts formed four estimates of the appropriate equity ratio for NTPC. The first two benchmarks represent measures of the average common equity ratio for utilities in Canada. The third benchmark captures equity ratios deemed appropriate for utilities of above-average risk by the Alberta Energy and Utilities Board. The fourth benchmark measures the equity levels approved for NTPC by this Board in the past.

The witnesses indicated that the benchmark equity ratios all fall in a range of 38% - 43%. Based on the analysis of the business risk faced by NTPC, the witnesses assessed NTPC's business risk as somewhat higher than that of the average shareholder-owned electric utility in Canada. Drs. Kryzanowski and Roberts considered a 42% equity ratio, just below the top end of the range, would be sufficient to result in a stand alone bond rating of BBB for NTPC.

With regard to NTPC's non-taxable status and its impact on coverage ratios and financial risks alluded to by Ms. McShane, the HC stated although bond rating agencies pay attention to ratios, there is no formula which translates ratios into bond rating. Considerable judgment comes into play. Simply having a key ratio (interest coverage, for example) below a certain level is not by itself grounds for a downgrade in practice. (HC Argument, p.47)

Views of the Board

The Board notes the expert witnesses' view that NTPC's business risk is higher (McShane) or somewhat higher (Kryzanowski and Roberts) than that of an average risk utility. The Board also notes Ms. McShane's view that the Corporation's non-taxable status has an impact on its coverage ratios and therefore the financial risk. The Board considers that although the coverage ratios do not necessarily dictate bond ratings, it would appear that the rating agencies include coverage ratios, among other factors, in their rating considerations and, to that extent, coverage ratios would appear to be relevant to the determination of capital structure for NTPC.

The Board notes NTPC's effective cost of long term debt somewhat exceeds the requested cost rate on equity. The Board sees this as an atypical cost structure because, for a typical utility, the cost of debt is generally less than the cost rate on equity. [Schedule 3.5] The relatively high debt cost appears to be largely the result of reflecting sinking fund earnings and investments in the effective cost of long term debt for NTPC and it would appear this situation may continue for some time until a substantial portion of the sinking fund debt instruments are retired. In the Board's view, any consideration of the appropriate capital structure for NTPC for the test years must take into account the reality of the presence of high cost debt in the capital structure since it has an impact on coverage ratios. The Board notes the capital structure recommendations of the HC witnesses reflect an equity ratio taking into consideration NTPC's business risks only. However, in the Board's view the Corporation's financial risk, as measured by indicators such as the coverage ratios, is also a relevant consideration in establishing an appropriate capital structure. The Board notes the HC calculated the coverage ratios excluding lease finance costs. (BR.HC-2) In the Board's view, the lease finance costs are a fixed contractual obligation by NTPC to DPC and should therefore be included in the calculation of coverage ratios.

For the purposes of this Decision, the Board accepts the capital structure proposed by NTPC as it appears to give due recognition to the relatively high cost of debt in relation to cost of equity in 2006/07 and 2007/08 and results in an acceptable level of interest coverage ratios for the test years.

The Board considers, with the eventual retirement of the high cost sinking fund debt, the coverage ratios and the financial risk of the utility would likely improve. Therefore, the capital structure accepted by the Board should not be viewed as solely reflecting NTPC's business risks but rather as one that takes into account NTPC's particular circumstances with respect to high cost debt.

4.4 Fair Return On Equity

NTPC requested allowed returns on equity of 10.5% and 10.75% for test years 2006/07 and 2007/08 respectively. Ms. McShane filed expert testimony supporting the NTPC proposed returns on equity. Drs. Kryzanowski and Roberts, who filed evidence on behalf of the HC, recommended returns on equity of 6.75% for 2006/07 and 7.20% for 2007/08.

Ms. McShane used the equity risk premium method; the discounted cash flow method and the comparable earnings test to estimate the returns on equity applicable to a benchmark utility as follows:

> "Ms. McShane's recommended returns on equity are based on the application of five different tests, three risk premium tests, the discounted cash flow test and the comparable earnings test. Ms. McShane used these tests to develop a fair return on equity for a benchmark Canadian utility, that is, a utility which, in light of its business and financial risks, would be able on a stand-alone basis, to achieve debt ratings in the A category. The returns on equity applicable to a benchmark utility would be approximately 10.0% for 2006/07 and 10.25% for 2007/08. A summary of the results of the tests applied by Ms. McShane (as updated in her Rebuttal Evidence, Ex. 12) are set out in the table below.

	Equity Risk Premium (ERP)
Test Year 2006/07	9.5%
Test Year 2007/08	9.75%
Discounted Cash Flow	9.0-9.5%
Comparable Earnings	12.0%"

(NTPC Argument, p.41, *ll*. 35 – p. 42, *ll*. 10)

Ms. McShane added a 50 basis points risk premium to the returns on equity applicable to the benchmark utility to reflect NTPC's higher risk in relation to the benchmark utility and came up with recommended returns on equity for NTPC of 10.50% for 2006/07 and 10.75% for 2007/08.

Drs. Kryzanowski and Roberts relied primarily on the equity risk premium test for their recommended returns. However, Drs. Kryzanowski and Roberts used the DCF Test to provide additional estimates of the Market Equity Risk Premium using both historical and forward-looking estimates of dividends and dividend growth at the market level.

Comparable Earnings ("CE") Test

The HC argued the results of the CE test should be given no weight in the determination of a fair return for the Corporation because the method is devoid of scientific merit, lacks theoretical underpinnings and suffers from substantive implementation difficulties.

> "Drs. Kryzanowski and Roberts point out that the basic problem is that there is neither a theoretical underpinning nor any empirical support for the comparable earnings approach to estimating a regulated fair rate of return for a utility. As an *ad hoc* approach to estimating a regulated fair rate of return, there are no agreed-upon rules for deciding upon how the Comparable Earnings Test should be implemented. They not only review 11 problems encountered in implementing a Comparable Earnings Test in their evidence but they illustrate the net effect of these problems by calculating the performance of the sample of 20 low risk Canadian industrials used by Ms. McShane over the 1994-2005 period to calculate accounting ROEs. They find that her sample outperforms the S&P/TSX Composite in that it not only has a higher mean return but also less risk. Thus, Ms. McShane has used a sample that has outperformed the S&P/TSX Composite over her test period both in terms of realized return and risk. Thus, Drs. Kryzanowski and Roberts recommend that the Board should not apply any weight to the Comparable Earnings evidence submitted by Ms. McShane. The method is not only devoid of scientific merit and theoretical underpinnings but its substantive implementation difficulties make it unsuitable to play a role in the determination of a fair rate of return for a utility." (HC Argument, p. 36)

Ms. McShane responded in detail to the HC's criticism of the CE test in her rebuttal evidence. (Ex.12 McShane Rebuttal) In essence, Ms. McShane's view as to the usefulness of the CE test may be summarized as follows:

> "…Regulation relies on an original cost rate base construct, or convention, rather than the market values to which the "scientific" cost of attracting capital tests apply. The comparable earnings test measures comparable returns measured in a manner compatible with the regulatory construct for measuring the equity investment in a utility, that is, on the basis of original cost. The cost of attracting capital tests do not." (Ex.12 McShane Rebuttal, p. 54, *ll*. 1581 - 1586)

Discounted Cash Flow ("DCF") Test

The HC submitted the DCF tests are unreliable when applied to specific firms in the same industry because of circularity problems and due to subjectivity in analysts' growth forecasts.

> "Ms. McShane also generates DCF estimates of a fair return on equity for a sample of U.S. gas and electric distributors. Due to a number of disadvantages, including circularity, discounted cash flow (DCF) tests are unreliable when applied to specific firms in the same industry." (HC Argument, p. 35)

In response, Ms. McShane submitted circularity is mitigated by using a sample of companies instead of the specific company and subjectivity is addressed by using a consensus growth forecast.

> "…However, circularity is mitigated by (a) using samples of companies, not the specific company to which the DCF test is being applied and (b) using the consensus of growth forecasts for the companies in the samples. With regard to the second, the use of the available consensus of analysts' earnings forecasts for the growth component eliminates the possibility that the results are colored by an analyst's own subjective views

of what the regulator should allow." (Ex.12 McShane Rebuttal, p. 44, *ll*. 1299 – p. 45, *ll*. 1305)

Equity Risk Premium ("ERP") Test

The benchmark equity return estimates under the ERP test provided by Ms. McShane are as follows:

	McShane	
	2006/07	2007/08
Risk free rate	4.25%	4.50%
Market equity risk premium	6.50%	6.50%
Beta	65% to 70%	65% to 70%
Equity risk premium	4.75%	4.75%
Allowance for financing flexibility	0.50%	0.50%
Benchmark utility return	9.50%	9.75%

The estimates for equity returns under the ERP test provided by the Drs. Kryzanowski and Roberts are as follows:

	Kryzanowski & Roberts	
	2006/07	2007/08
Risk free rate	4.20%	4.65%
Market equity risk premium	4.90%	4.90%
Beta	50.0%	50.0%
Equity risk premium	2.45%	2.45%
Allowance for financing flexibility	0.10%	0.10%
Benchmark utility return	6.75%	7.20%

The significant differences between the two sets of estimates are explained by differences in the estimates included for the market equity risk premium ("**MERP**"), the beta value (which is a measure of the risk of an average risk utility stock relative to the market) and the allowance for financing flexibility

Ms. McShane indicated her 6.5% market equity risk premium estimate recognizes the expected value of the equity market return developed from historic values in conjunction with the current and forecast low levels of interest rates.

> "Based on the analysis of the historic risk premiums, primarily in Canada and the U.S., with focus on the arithmetic averages and with consideration given to trends in the equity and government bond markets in both countries, a reasonable estimate of the expected value of the equity market risk premium at the forecast levels of long-term government bond yields is approximately 6.5%. The 6.5% estimate of the equity market risk premium explicitly recognizes the expected value of the equity market return developed from historic values in conjunction with the current and forecast low levels of interest rates." (Ex. 2, Appendix B, McShane Evidence, p.33, *ll*. 900 - 907)

The HC witness expressed several concerns with Ms. McShane's forecast MERP.

> "In contrast, Ms. McShane uses the historic average MERP for Canada, the U.S. and the U.K. over the period 1947-2006 to obtain an estimate of the MERP going forward of 6.5%. Her estimate is inappropriately high for four reasons. First, the chosen time period results in an inflated estimate of the going-forward likelihood of achieving the high realized returns on equities and low realized returns on bonds that followed World War II. This period begins with rapid economic growth due to pent up demand from the war period and administered low interest rates. Using the mean gives an equal weight to each year in this early period. Second, minimal or no weight is placed on the declining trend of MERPs for the three markets over this time period. Third, no adjustments are made for differences in risks across the market proxies used to calculate the MERP in the different countries. Fourth, no adjustments are made for the effect of equity re-valuations over this period of time unless one believes that price-to-dividend multiples will exhibit a similar three-fold increase over the next 60 years." (HC Argument, p. 30 - 31)

In her rebuttal evidence, Ms. McShane responded to the first 3 concerns of the HC. First, with regard to the time period chosen for the analysis, Ms. McShane stated as follows:

> "…It would be inappropriate to "cherry pick" the post World War II period. Equally, it could be argued that other sub-periods are not representative of future expectations and whose inclusion or exclusion might inflate or deflate the estimate of the expected long-term forward looking returns or risk premium..." (Ex.12 McShane Rebuttal, p.38, *ll*. 1131 - 1134)

Ms. McShane explained that observed risk premiums have declined because the achieved returns on long-term Canada bonds reflect historic yields that were much higher than they are expected to be and the significant capital gains that have occurred since long Canada bond yields began to decline.

> "..The reason that the observed risk premiums have declined is because the achieved returns on long-term Canada bonds reflect (1) historic yields that were much higher than they are expected to be; and (2) the significant capital gains that have occurred since long Canada bond yields began to decline…." (Ex.12 McShane Rebuttal, p. 40, *ll*. 1191 - 1194)

With regard to the HC's view, no adjustments have been made for the market proxies used because Ms. McShane did not consider such adjustments were needed.

> "With respect to the benefits of international diversification, one of the principal reasons for investing abroad is the opportunity to earn similar or higher returns than available in the domestic market while bearing similar or lower risk. From this perspective, there is no rationale for concluding that the returns and risk premiums that Canadian investors would anticipate from investing abroad would be reduced from those anticipated from domestic markets only. (Ex.12 McShane Rebuttal, p. 42, *ll*. 1236 - 1241)

Ms. McShane explained one of the reasons for difference between her estimate of market equity risk premium and Drs. Kryzanowski and Roberts' estimate relates to the weight given to the arithmetic versus geometric averages in the estimation of historic market risk premiums. Drs. Kryzanowski and Roberts gave more weight to geometric averages based on their finding that historically returns have been mean reverting. Mean reverting essentially means that low returns can be expected to be followed by high returns, so that investors can reasonably expect that, over time, returns will return to some long term average. Therefore, the estimate of the required future equity risk premium should take into account the predictability of future returns as indicated by the mean reversion, by giving some weight to the historic compound, or geometric, return.

Drs. Kryzanowski and Roberts indicated they had conducted a number of tests of robustness of their MERP estimate and conclude that it should not be increased from their estimate of 4.9%.

With respect to the beta values, the difference between the McShane approach and that of Drs. Kryzanowski and Roberts relates mainly to the fact Ms. McShane adjusted her raw beta estimates upwards to provide a better correlation between utility risk and return.

> "Using adjusted betas can mitigate the deficiencies in "raw" betas. Adjusting betas entails moving betas above and below the market mean of 1.0 toward the market mean. The adjustment that is used by the major commercial suppliers of betas uses a formula that gives approximately two-thirds weight to the stock's own beta and one-third weight to the market mean beta of 1.0. Use of adjusted betas implicitly recognizes that "raw" utility betas are not adequate explanators of utility returns. For example, "raw" betas do not capture utilities' interest rate sensitivity. The objective of the relative risk adjustment is to predict the investors' required return. Adjusted betas provide a better correlation between utility risk and return than "raw" betas." (Ex. 2, Appendix B McShane Evidence, p. 38, *ll*. 1031 - 1040)

Drs. Kryzanowski and Roberts disagreed with the upward adjustment of raw betas recommended by Ms. McShane.

> "…McShane uses the Value Line method to adjust her betas upwards when she should not. Drs. Kryzanowski and Roberts provide various rationales in Sections IV and VI of their evidence why the beta of an average-risk (never mind low-risk) utility should not be adjusted towards one. Not only is it logically inconsistent to assume that the average beta of a mature industry is equivalent to that of the overall market but empirical findings upon which this adjustment is based reveal that individual betas revert to the sample mean, which in the case of an average-risk utility is itself. Drs. Kryzanowski and Roberts also demonstrate why the interest-rate sensitivity rationale for using a variant of the adjusted beta method for utilities is flawed and is based on a misunderstanding of asset pricing theory and empirical tests. Since Ms. McShane basically uses the sample average utility beta as her beta estimate for a low-risk utility benchmark, no upward adjustment is needed to offset the tendency of the beta of a specific utility to regress to that same sample average utility beta..." (HC Argument, p. 32)

Drs. Kryzanowski and Roberts explained why in their view adjustment of beta's for interest rate sensitivity is not necessary.

> "…Over the long run, we would expect the average return on long Canada's to be equal to the yield on long Canada's (the proxy for the risk-free rate in rate of return settings). This is because our expectation is that rates would fluctuate randomly so that returns would be above yields to maturity in some periods and below them in others. Thus, while it is true that utility returns are sensitive to interest rates, it is not true that interest rate risk will have a positive risk premium over the long run. (Ex. 8; p. 83)

With respect to the financing flexibility allowance of 50 basis points recommended by Ms. McShane, Drs. Kryzanowski and Roberts noted the Board should consider the excess returns earned by utility investors when establishing the financing flexibility add-on to the return on equity ("**ROE**") in this rate hearing.

> "…In other words, providing generous rates of return allowances to enhance the financial integrity and flexibility of these utilities (without requiring these utilities to establish a reserve account to capture these insurance premiums) just over-compensates investors given the high dividend payout practices of many Canadian utilities. Drs. Kryzanowski and Roberts do not recommend the establishment of such a reserve account. Instead, they recommend that the Board consider the excess returns earned by utility investors when establishing the financing flexibility add-on (or kicker) to the ROE in this rate hearing..." (HC Argument, p. 38)

Additional Risk Premium on Benchmark Return Estimates

Ms. McShane recommended an additional 50 basis points risk premium on the returns on equity applicable to the benchmark utility to reflect NTPC's higher risk in relation to the benchmark utility. In her view, NTPC would be a BBB rated utility at the proposed capital structure and therefore she indicated an additional risk premium is required on the basis of cost of debt differentials between a BBB rated utility and a benchmark A rated utility.

> "The estimation of the difference in return that would be warranted for NTPC's higher business risks is in part a matter of professional judgment, but should be constrained by factual support. Ms. McShane's direct evidence demonstrates that the difference in the cost of debt as between a utility with debt ratings in the A category and a utility whose debt is rated in the BBB category is approximately 0.60%. The difference in the cost of debt between an A rated benchmark utility and a BBB rated utility (which NTPC would be on a stand-alone basis) serves as a proxy for the incremental return that an equity investor would require to invest in NTPC. On the basis of cost of debt differentials, Ms. McShane's incremental equity risk premium of 0.50% for the Corporation should be viewed as the minimal differential return required relative to a benchmark utility. Her proposed differential is fully consistent with the 0.60% differential adopted by the Board in respect of the allowed return for NUL in Decision 9-2006 (March 2006)." (NTPC Argument, p. 45, *ll*. 13 - 23)

Drs. Kryzanowski and Roberts did not agree that an incremental risk premium on the benchmark return is required because in their view Ms. McShane's estimated benchmark returns would have the effect of rewarding NTPC twice for the same incremental risk that is already reflected in the capital structure of an average-risk utility.

> “When she estimates the risk premium, she incorrectly uses a sample or an industry index, which is really for an average and not low-risk utility. Recognizing her error, Drs. Kryzanowski and Roberts challenged her view that an incremental equity risk premium is required. Such an equity risk premium would have the effect of rewarding NTPC twice for the same incremental risk that is already reflected in the capital structure of an average-risk utility.” (HC Reply, p. 21)

Views of the Board

The Board notes the CE method provides a measure of the actual realized returns on the book value of comparable risk securities. In this regard the CE test differs from other tests such as the equity risk premium test, which attempt to measure the expected return on the market value of securities. In an original cost rate base jurisdiction where the fair return is established on the basis of the book value of assets, the awarded returns must reflect investors’ expectations of market returns on comparable risk securities. These expectations of market returns cannot, in the Board’s view, be measured by the book returns of comparable risk securities because of differences between the book values and market values. Rather, the investors’ expectations are appropriately measured in relation to the market value of comparable risk securities. In the Board’s view the CE method fails to meet this requirement. Therefore the Board will not give any weight to the CE method in determining the fair return on equity.

The Board notes the DCF test, similar to other tests, has certain drawbacks. However, in view of the mitigating factors referred to by Ms. McShane, the Board considers it appropriate to consider the DCF test among other tests in determining the fair rate of return on equity.

The Board notes NTPC's submission that based on the British Columbia Utilities Commission's ("**BCUC's**") automatic adjustment mechanism, the market equity risk premium would be much closer to Ms. McShane's 6.5% than Drs. Kryzanowski and Robert's 4.9%.

> "The most recent regulatory determination of the market risk premium was in 2006 by the British Columbia in which, having heard all the evidence, concluded that the market risk premium was 5.8% at a long-term Canada bond yield of 5.25%. The forecast yield on long Canada bonds in this proceeding is considerably lower than 5.25% (4.5% and 4.65% for 2007/08 by Ms. McShane and Drs. Kryzanowski and Roberts respectively). Based on the BCUC's automatic adjustment mechanism, which, similar to those used by other Canadian regulators, is premised on an inverse relationship between interest rates and risk premiums, the indicated market risk premium at a 4.5% to 4.65% long Canada yield would be higher than 5.8%, much closer to Ms. McShane's 6.5% than Drs. Kryzanowski and Roberts's 4.9%." (NTPC Reply, p. 29, *ll*. 25 - 33)

The Board notes NTPC's submission that the risk premium looking forward should be higher than the historic values when bond market returns are expected to be lower.

> "…Ms. McShane's Rebuttal evidence pointed out that Drs. Kryzanowski and Roberts acknowledged that there has been no material change in the equity market return. If equity market returns are approximately the same, but bond market returns are expected to be lower, then it follows that the risk premium looking forward should be higher than the historic values." (NTPC Reply, p. 29, *ll*. 10 - 14)

The Board considers Drs. Kryzanowski and Roberts' estimated market equity risk premium to be downwardly biased since the witnesses do not appear have given recognition to market equity risk premium increases resulting from lower prospective bond market returns, compared to the historic period.

The Board, having reviewed the foregoing, considers a market equity risk premium of 6% to be appropriate under current long-term interest rate conditions.

The Board also considers Ms. McShane's adjusted beta values to be on the high side when viewed in relation to the raw beta estimates based on observations during a relatively stable interest rate environment such as the 30 month periods, January 2003 to June 2005 and July 2003 to December 2005. (Ex.12 McShane Evidence, p.36, Table 7)

The Board notes Drs. Kryzanowski and Roberts' view that beta values need not be adjusted for interest rate risk because interest rate risk will not result in a positive risk premium over the long run. However, the beta estimates provided by the witnesses in Schedule 4.10 of Exhibit 8 show wide variations in beta values for each 5-year period analyzed. This indicates inference of average beta values from such wide dispersions in beta values may not produce reliable results.

The Board considers a 50 basis point addition for financing flexibility is consistent with similar allowances awarded in other jurisdictions and is appropriate in order to maintain the financial integrity of the utility. The Board is not persuaded that past excess earnings need to be considered in assessing the appropriateness of an allowance for financing flexibility for a utility that is regulated on a forward test year basis. Under forward test year regulation, there is an expectation the probability of actual returns being higher or lower than the allowed return is about the same.

The Board notes Ms. McShane's view that the proposed capital structure would result in a BBB rating for the Corporation. The Board notes the high cost of debt in NTPC's capital structure and considers the 50 basis points upward adjustment recommended by Ms. McShane is reasonable under the circumstances to compensate for the relatively high financial risk of the utility.

Although the Board has accepted an upward adjustment to the equity return estimates as noted above, in future proceedings, the Board would prefer to see all of the business risk adjustment reflected in the capital structure rather than in the capital structure as well as in the return on common equity.

The Board notes NTPC filed its Application in November of 2006, about eight months into the first test year. Since the Corporation would have had knowledge of actual events pertaining to a substantial part of the first test year, the Board considers the Corporation's forecast risks were mitigated to some extent. Therefore the Board considers it reasonable to reduce the allowed rate of return on equity for 2006/07 by 40 basis points to recognize this risk reduction.

Having considered the ERP test and the DCF test and the factors discussed above, the Board determines the fair rate of return on equity to be 8.60% for 2006/07 and 9.25% for 2007/08.

For purpose of calculating the return component of the DPC lease payments, the Board does not consider the 40 basis point reduction in NTPC's return on equity for 2006/07 noted above should apply because this is a specific adjustment applicable to NTPC's particular circumstances in 2006/07. Accordingly, the Board directs NTPC to use fair returns on equity of 9.00% for 2006/07 and 9.25% for 2007/08 in order to calculate the DPC lease payments in the Phase 1 refiling.

5. PRODUCTION FUEL AND PURCHASED POWER

NTPC produces power using two fuels, diesel and natural gas, and also purchases power for resale in Norman Wells.

NTPC is seeking the Board's approval for $17.150 million and $17.848 million in production fuel and purchased power expenses in 06/07 and 07/08, respectively. These amounts represent increases of $2.635 million and $3.333 million, respectively, from the $14.515 million approved in the 01/03 Settlement.

Of the $17.150 million forecast in 06/07, $0.511 million will be expensed to the hydro water stabilization funds so only $16.639 million is included in the 06/07 revenue requirement.

Of the $17.848 million forecast in 07/08, $0.425 million will be expensed to the hydro water stabilization funds so only $17.423 million in included in the 07/08 revenue requirement.

NTPC has been attempting to reduce the fuel expenses with two notable projects being the addition of a third gas engine in Inuvik and the purchase of the Bluefish Generating Station. These efforts have allowed NTPC to offset approximately half of the fuel price impact on a Corporate-wide basis.

Three issues were raised by the interveners on this matter:

1) Diesel and natural gas engine fuel efficiencies;
2) Losses and station service; and
3) Fuel Pricing in Inuvik

These three issues are addressed by the Board in Sections 5.1, 5.2 and 5.3. Subject to the Board's directions in these three sections and in Section 10.1.1 concerning the water stabilization fund, NTPC's proposed production fuel and purchased power expenses forecast for 06/07 and 07/08 are approved by the Board.

5.1 Fuel Efficiencies

The topic of fuel efficiencies, for diesel in all communities and natural gas in Inuvik, was pursued by the TGC.

5.1.1 Diesel

Diesel efficiency data which has been provided over the course of this review is compiled in Table 5.1. The data is drawn from the Phase 1 Application (Schedules 2.1, 2.2 and 2.3, Schedules 3.3.1 and 3.3.2 and Appendix A) and information request responses (BR.NTPC-6, TGC.NTPC-20 and TGC.NTPC-32).

Table 5.1 – Diesel Plant Efficiency (kWh/L)

	02/03 Settlement	**02/03 Actual**	**03/04 Actual**	**04/05 Actual**	**05/06 Actual**	**06/07 Forecast**	**07/08 Forecast**
Yellowknife	3.698	Not Provided	3.776	3.797	3.844	3.500	3.500
Behchoko	3.000	Not Provided	Not Provided	Not Provided	Not Provided	3.250	3.250
Fort Resolution	Not Provided	Not Provided	NA	NA	3.459	3.459	3.459
Fort Smith	3.440	Not Provided	3.259	3.323	3.177	3.277	3.277
Hydro	**3.673**	**Not Provided**	**Not Provided**	**3.779**	**3.725**	**3.458**	**3.442**
Wha Ti	3.147	Not Provided	3.624	3.654	3.778	3.711	3.711
Gameti	3.464	Not Provided	3.539	3.254	3.259	3.398	3.398
Lutsel K'e	3.793	Not	3.751	3.792	3.772	3.778	3.778

		Provided					
Fort Simpson	3.763	Not Provided	3.749	3.774	3.713	3.755	3.755
Fort Liard	3.665	Not Provided	3.764	3.709	3.636	3.725	3.725
Wrigley	3.617	Not Provided	3.645	3.413	3.386	3.525	3.525
Nahanni Butte	2.311	Not Provided	2.407	2.440	2.594	2.511	2.511
Jean Marie River	2.520	Not Provided	2.589	2.591	2.907	2.749	2.749
Inuvik	3.450	3.579	3.603	3.693	3.524	3.635	3.635
Norman Wells	Not Provided	Not Provided	0.000	3.277	3.506	3.414	3.414
Tuktoyaktuk	3.581	Not Provided	3.733	3.680	3.622	3.697	3.697
Fort McPherson	3.381	Not Provided	NA	NA	3.609	3.609	3.609
Aklavik	3.428	Not Provided	3.570	3.421	3.299	3.475	3.475
Deline	3.471	Not Provided	3.475	3.591	3.515	3.546	3.546
Fort Good Hope	3.556	Not Provided	3.565	3.606	3.507	3.576	3.576
Tulita	3.587	Not Provided	3.660	3.591	3.616	3.634	3.634
Paulatuk	3.397	Not Provided	3.464	3.508	3.481	3.492	3.492
Sachs Harbour	3.281	Not Provided	3.168	3.242	3.073	3.189	3.189
Tsiigehtchic	3.279	Not Provided	3.556	3.525	3.506	3.537	3.537
Colville Lake	2.414	Not Provided	2.864	2.773	3.081	2.957	2.957
Ulukhaktok	3.579	Not Provided	3.560	3.552	3.675	3.616	3.616
Diesel	**3.502**	**Not Provided**	**Not Provided**	**3.551**	**3.546**	**3.596**	**3.599**
Overall	**3.575**	**3.654**	**Not Provided**	**3.636**	**3.559**	**3.587**	**3.592**

With 4 exceptions, on a community-by-community basis the 06/07 and 07/08 forecast fuel efficiencies are based on the approach agreed to in the 01/03 Settlement which calculates the forecast efficiency based on the last 3 years of actual efficiency, weighted 3 for the highest efficiency year, 2 for the middle efficiency year and 1 for the lowest efficiency year.

The 4 exceptions to this method of forecasting efficiencies are:

Yellowknife: With the addition of Bluefish and the reduced mining loads, generation at the Jackfish plant has been significantly reduced. Jackfish will primarily be used as a standby plant. Standby plants usually have lower efficiencies than primary plants as a result of fuel being used to warm-up and cool down the engines but with no power being produced. As a result, NTPC does not believe that Jackfish will achieve its historic efficiencies. The 3.500 kWh/L is an operational estimate for Jackfish's new status as a standby plant.

Fort Resolution: The plant is new so the only year of actual efficiencies (05/06) is used for 06/07 and 07/08.

Norman Wells: The plant has only 2 years of actual efficiencies so those 2 years were taken as representative of the actual plant efficiency with a weighting of 3 for the highest efficiency and 2 for the lowest.

Fort McPherson: The plant is new so the only year of actual efficiencies (05/06) is used for 06/07 and 07/08.

NTPC does not apply any weighting to new engines installed in the test years (unless it is for a new plant), nor does it make any adjustments for any decreased efficiency for older engines. NTPC also provided its view that in the future it is likely that new engines will be less efficient due to requirements to meet new emissions standards.

The TGC pursued questioning on the fuel efficiency issue but this questioning was not driven by differences with NTPC over the fuel efficiency data that was provided. The TGC was primarily concerned with bolstering arguments being put forward by the TGC with regards to 1) altering the forecast efficiencies of the Inuvik natural gas engines, which will be dealt with later in this section; and 2) the use of actual fuel efficiencies for the fuel stabilizations funds, which will be dealt with in Section 12.2 of this decision.

The TGC, in Undertaking 13, had requested an explanation from the NTPC as to the impact of changing fuel efficiencies (01/03 Settlement to 06/07 forecasts) on the overall costs of diesel fuel. NTPC's response explained that the change from the 02/03 to the 06/07 diesel efficiencies was responsible for a $122,000 decrease in diesel expense on a corporate-wide basis.

The TGC did not directly address the diesel fuel efficiency issue in either its argument or reply. In its argument, NTPC submitted that "*its fuel efficiency forecasts for the test years are reasonable and should be approved*."

Views of the Board

The Board approves of the alternative methods for calculating the forecast fuel efficiencies for Yellowknife, Fort Resolution, Norman Wells and Fort McPherson.

The Board notes that there are 4 communities (Nahanni Butte, Jean Marie River, Sachs Harbour and Colville Lake) with fuel efficiencies, which are substantially lower than the other communities; however no detailed explanation has been provided justifying this situation. The Board directs NTPC at the next GRA to provide a detailed analysis as to 1) why the fuel efficiencies in Nahanni Butte, Jean Marie River, Sachs Harbour and Colville Lake are so low; and 2) what NTPC has done and will do to improve the fuel efficiencies in these 4 communities.

The Board notes that unlike other aspects of the GRA, the 07/08 fuel efficiency forecasts do not incorporate the 06/07 forecasts. Given the generally upward trend in fuel efficiencies, it is the Board's view that calculating the 07/08 forecasts without including the 06/07 forecasts could result in customers forgoing a year's worth of fuel efficiency improvements. Since this matter was not fully canvassed as part of these proceedings the Board does not consider it appropriate to make any adjustments in this regard for the purposes of these proceedings. However, the Board directs NTPC to give due weight to the first test year forecast fuel efficiencies in order to calculate the second test year fuel efficiency forecasts, in the next GRA.

It is the Board's view that the analysis of this issue would have been simplified had the data shown in Table 5.1 been provided in such a format as part of the Phase 1 application. The Board directs NTPC, in the next GRA, to provide an updated version of Table 5.1 that includes the forecast and actual diesel efficiencies for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.

5.1.2 Natural Gas in Inuvik

Gas efficiency data in Inuvik, which has been provided over the course of this review, is compiled in Table 5.2. The data is drawn from the Phase 1 Application (Schedule 2.3, Schedules 3.3.1 and 3.3.2) and information request responses (BR.NTPC-6 and TGC.NTPC-20).

Table 5.2 – Inuvik Gas Plant Efficiency (kWh/m^3)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Gas Efficiency	3.600	3.429	3.389	3.391	3.409	3.399	3.399

The 01/03 Settlement set the gas efficiency at 3.600 kWh/m^3. This was based on 2 years of actual experience with the 2 engines that had been installed in Inuvik in 1999.

Gas consumption is forecast to rise considerably as a result of the installation of a third gas unit in Inuvik in 2006. A 28.7% increase in gas consumption is forecast for 2006/07 and 1.3% for 2007/08. However, gas efficiency is forecast to be steady across the two test years at 3.399 kWh/m^3. This forecast is based on energy generation of 95% gas and 5% diesel as opposed to the historical average of 76% gas and 24% diesel.

In its evidence, the TGC took issue with NTPC's forecast gas efficiency. The TGC suggested that the addition of the third engine in Inuvik should result in an increase in the gas efficiency. The TGC suggested an efficiency increase of at least 5% is appropriate and that, based on a 5% improvement, the fuel costs for Inuvik should be reduced by $177,000 in 2006/07 and $179,000 in 2007/08.

In its rebuttal, the NTPC provided the following evidence to support its proposed gas efficiency.

> "Mr. Merani's evidence suggests that an increase to the fuel efficiency rate for Inuvik is warranted. He appears to arrive at this conclusion by relying on two factors:
>
> - the forecast efficiency is lower than the manufacturer's stated test efficiency rating; and
> - because replacing diesel engines in other communities has resulted in improved fuel efficiency.
>
> In the Corporation's view neither of these factors is a valid reason for adjusting the forecast gas plant efficiency in Inuvik.

The manufacturer's efficiency rating is seldom, if ever, achievable in practice. Actual operating conditions influence the efficiency achieved. The forecast fuel efficiencies used to calculate fuel expense reflect the overall efficiency of all units in a plant. The plant efficiencies are impacted by the operating loads; the efficiency of individual units; how the units are dispatched; and percentage loading on the individual engines. Also, fuel efficiencies calculated by the manufacturer do not include fuel consumed during unit start-up and cool down periods. It is therefore not reasonable to adjust the forecast gas plant efficiency based on the manufacturer's rated efficiency. Rather, the more accurate measure of fuel efficiency is to consider recent historical performance of the actual unit when available and, if not available, recent historical performance of similar units at the same generation plant.

Mr. Merani's evidence cites instances where replacing older diesel engines with newer diesel units improved the fuel efficiency at the plant. In the Corporation's view, comparing the efficiency improvements observed as a result of replacing older diesel engines with newer diesel engines to the installation of the 3rd gas genset in Inuvik is not a reasonable basis to suggest that the gas plant efficiency in Inuvik should be adjusted.

Newer diesel engines typically have electronic controls and/or electronic fuel injection – where the primary target is to produce as much power as possible while utilizing the least amount of fuel. This contrasts with the much older technology typically being replaced in diesel plants. In these situations fuel efficiency often is observed to improve. However, it should be noted that this may not continue to be the case in the future as current diesel technology has largely maximized fuel efficiency to the extent possible. Further, it should be noted that diesel engine manufacturers are in many cases faced with competing design objectives of fuel efficiency and reduced emissions. In some newer diesel engines, fuel efficiency is actually lower than previous technologies, in order to maximize emissions reduction objectives.

By contrast, the new natural gas genset in Inuvik is only 4-5 years newer than the existing natural gas gensets (it was manufactured in 2001). The new unit has the same engine control system/fuel system and the same efficiency ratings as the other 2 units. The 3rd gas genset was not justified based on improving efficiency but rather on displacing consumption of diesel fuel. In the Corporation's view there is no reasonable basis to expect that the 3rd gas genset will materially affect the gas plant efficiency in Inuvik. (Ex. 12 NTPC Rebuttal, p. 14, *ll*. 30 – p. 15, *ll*. 35)

Undertaking 9 at the hearing requested NTPC to provide the 2 years of actual data that was relied upon in setting the fuel efficiency to 3.600 kWh/m^3 in the 01/03 Settlement. NTPC reported that for 1999/2000, the actual gas efficiency was 3.51 kWh/m^3 and for 2000/2001, it was 3.65 kWh/m^3.

Undertaking 10 requested the manufacturer's rated efficiencies for the gas engines. NTPC's response was:

> "MR. STEPHEN KERR: The manufacturer's rated efficiencies for the Inuvik gas engines. At 50 percent load the efficiency is 3.7 kilowatt hours per metre cubed. At 75 percent load, 4.01 kilowatt hours per metre cubed. At 100 percent load, 4.23 kilowatt hours per metre cubed.
>
> And these efficiencies are based on one (1) hour of continuous operation at those loads, but it does not take into consideration any fuel consumed to warm up or cool down the engine." (Tr. Vol. II, p. 20, *ll*. 13 - 22)

This explanation for Undertaking 10 was questioned by the TGC.

> "MR. AZAD MERANI: Before I go on to my cross, just a quick question on the undertakings.
>
> Mr. Kerr, you mentioned the Inuvik gas engine had an efficiency rating depending on the percent loading; that was the manufacturer's recommended ratings.
>
> Are you able to tell me what the engines are running at on an actual basis? Are they fairly close to 100 percent or thereabouts?
>
> MR. STEPHEN KERR: Subject to check, I would say no. The Inuvik gas engines are -- they would follow the load in Inuvik, so I would say rarely are these engines base loaded.
>
> MR. AZAD MERANI: Certainly not 50 percent; you'd say it would be higher than 50, close to 75 percent or so?
>
> MR. STEPHEN KERR: Again, something to check. They probably operate somewhere between 50 and 75 percent, again, depending on the load." (Tr. Vol. II, p. 27, *ll*. 16 – p. 28, *ll*. 8)

In its argument, NTPC suggested that the Board should disregard the TGC suggestions of a 5% improvement in gas efficiency and provided the following explanation.

> "Fuel efficiency for the Town of Inuvik is forecast in the Application at 3.399 kW.h/m^3 for both test years. As discussed in section 4(b) above, that forecast is based on a weighted average of the past three years' actual plant efficiencies and no adjustment was made for the third Inuvik gas engine installed in 2006/07.
>
> Mr. Merani has suggested that "…there is no doubt the addition of the third engine in Inuvik should result in an increase in the gas efficiency. This review of changes in efficiency associated with a new plant or engine suggests an efficiency increase of at least 5% is appropriate."
>
> The evidence does not support Mr. Marani's suggestion. The third Inuvik gas engine is not likely to have a better fuel efficiency than the existing gas gensets that are only 4 to 5 years older. Further, manufacturer's fuel efficiency ratings are not useful for GRA forecasts. As Mr. Kerr noted, manufacturer's ratings "…are based on one (1) hour of continuous operation at those loads, but it does not take into consideration any fuel consumed to warm up or cool down the engine." Clearly the manufacturer's fuel efficiency ratings do not reflect real world conditions, which a GRA forecast is intended to mirror, and should not be applied in this case.
>
> Consequently, a 3.399 kW.h/m^3 forecast fuel efficiency for the Town of Inuvik is reasonable and the Board should disregard Mr. Merani's suggestion. (NTPC Argument, p. 69, *ll*. 7 – 22)

In its argument, the TGC restated its position as follows:

> "The TGC submit the recommendations in its evidence to increase Inuvik's gas efficiency rating for the Test Years 2006/07 and 2007/08, by 5%, from 3.399 Kwh/cubic meter to 3.569 Kwh/cubic meter, remain valid for the following reasons:
>
> - As noted in the TGC evidence, when a new engine is installed (for example, in Fort Providence), or when a new plant is installed, we

generally see an increase in fuel efficiency rate; this increase has been in the range of 5.60% to 6.99%

- Contrary to the evidence filed in TGC.NTPC-20, the 2002/04 has heat rate was filed based on actual experienced gas heat rates of between 3.510 Kwh/cubic meter in 1999/2000 and 3.650 Kwh/cubic meter in 2000/01
- The actual gas heat rate in 2002/03 was 3.429 Kwh/cubic meter
- At 50% loading, the manufacturer's test heat rate is 3.700 Kwh/cubic meter whereas as 75% loading, it is 4.010 Kwh/cubic meter; considering these engines run at about 50 to 75% loading, and taking into account the consumption of fuel during the warming up and cooling down processes, the recommended revised rate of 3.569 Kwh/cubic meter appears reasonable.
- The simple average of the above noted heat rates is 3.529 Kwh/cubic meter [(3.510+3.650+3.429)/3], significantly higher than the 3.399 Kwh/cubic meter used in the GRA.
- Using the weighting of 3:2:1 for the data available, a rate of 3.565 Kwh/cubic meter is obtained:

Year	Heat Rate	Weighting	Weighted HR
1999-00	3.5100	2	7.02
2000-01	3.6500	3	10.95
2002-03	3.4290	1	3.429
Total	10.5890	6	21.399
Simple Average	3.5297		
Weighted Average			3.5665

- The use of the most recent data available on the record is appropriate as acknowledged by NTPC:

Rather, the more accurate measure of fuel efficiency is to consider recent historical performance of the actual unit when available and, if not available, recent historical performance of similar units at the same generation plant. " (TGC Argument, p. 22 – 23)

The TGC and NTPC both discussed this issue further in their reply arguments.

Views of the Board

It is the Board's view that the TGC has not justified why NTPC should use actual gas efficiencies from 99/00, 00/01 and 02/03 when there is more recent (03/04, 04/05 and 05/06) actual data available for use. Similarly, the Board is not convinced that the 3rd gas engine in Inuvik will produce efficiencies substantially different than first two engines given the young age of the first two engines. It is the Board's view that the improved diesel efficiencies achieved when older engines have been replaced by newer engines is not comparable to the situation in Inuvik with the addition of a 3rd gas engine.

The Board approves of the forecast gas efficiencies for 06/07 and 07/08.

In keeping with the Board's direction on diesel efficiencies, the Board directs NTPC to give due weight to the first test year gas efficiency forecasts in order to calculate the second test year gas efficiencies, in the next GRA.

The Board is also concerned about two other issues.

Drop in Efficiency: For 1999/2000, the actual gas efficiency was 3.51 kWh/m^3 and for 2000/2001, it was 3.65 kWh/m^3. Since that time the efficiency has been substantially lower at about 3.4 kWh/m^3. NTPC has not provided a satisfactory explanation as to why the gas efficiency has decreased from the first two years of operation. The Board directs NTPC, at the next GRA, to provide an analysis as to why the recent gas efficiency has dropped substantially from 99/00 and 00/01.

Manufacturer's Rating: As acknowledged by NTPC, the gas engines generally operate in the range of 50% to 75% of capacity. The manufacturer's efficiency ratings at these loads are 3.7 kWh/m^3 and 4.01 kWh/m^3, respectively, which is substantially higher than NTPC's forecast of 3.399 kWh/m^3. While the Board can accept that the actual operation of the engines can differ from the manufacturer's ratings, the magnitude of the discrepancy is of concern to the Board. The Board directs NTPC, at the next GRA, to provide a detailed analysis as to why the actual gas efficiencies are so much lower than the manufacturer's ratings.

It is the Board's view that the analysis of this issue would have been simplified had the data shown in Table 5.2 been provided in such a format as part of the Phase 1 application. The Board directs NTPC, in the next GRA, to provide an updated version of Table 5.2 that includes the forecast and actual gas efficiencies for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.

5.2 Losses and Station Service

5.2.1 Losses

Loss data which has been provided over the course of this review is compiled in Table 5.3. The data is drawn from the Phase 1 Application (Schedules 2.1, 2.2 and 2.3, and Schedules A.1 to A.27) and information requests (TGC.NTPC-32 and HC.NTPC-9(g)).

Table 5.3 – Losses (MWh and % of Generation)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Behchoko	Included in Snare System figures						
Dettah	Included in Snare System figures						
Snare	10,920	11,691	7940	10,490	8314	6642	7579
	5.2%	5.6%	3.9%	4.6%	4.2%	3.4%	3.9%
Fort Resolution	Included in Taltson System figures						

Fort Smith	Included in Taltson System figures						
Taltson	4225	7252	5912	8670	5591	6742	6818
	6.7%	11.2%	9.6%	13.2%	8.7%	10.2%	10.2%
Hydro	**15,144**	**Not Provided**	**Not Provided**	**19,160**	**13,905**	**13,384**	**14,397**
	5.5%	**Not Provided**	**Not Provided**	**6.5%**	**5.3%**	**5.2%**	**5.5%**
Wha Ti	116	Not Provided	Not Provided	111	113	135	135
	6.2%	Not Provided	Not Provided	6.5%	6.6%	7.8%	7.8%
Gameti	39	Not Provided	Not Provided	39	59	43	42
	4.1%	Not Provided	Not Provided	4.0%	5.9%	4.4%	4.3%
Lutsel K'e	94	Not Provided	Not Provided	80	79	90	92
	6.2%	Not Provided	Not Provided	5.0%	5.0%	5.6%	5.6%
Fort Simpson	433	260	456	408	460	446	453
	5.4%	Not Provided	Not Provided	5.1%	5.8%	5.5%	5.5%
Fort Liard	258	498	170	251	232	254	244
	7.0%	Not Provided	Not Provided	8.8%	8.4%	9.0%	9.0%
Wrigley	58	Not Provided	Not Provided	32	55	45	41
	7.0%	Not Provided	Not Provided	4.1%	7.5%	6.2%	6.1%
Nahanni Butte	21	Not Provided	Not Provided	41	22	37	35
	5.2%	Not Provided	Not Provided	10.4%	5.4%	9.4%	9.4%
Jean Marie River	19	Not Provided	Not Provided	57	58	63	65
	7.0%	Not Provided	Not Provided	17.3%	19.0%	19.0%	19.0%
Inuvik	2020	1929	584	1221	1318	1854	1880
	7.0%	Not Provided	Not Provided	4.0%	4.3%	6.0%	6.0%
Norman Wells	515	Not Provided	Not Provided	1256	1232	1121	1157
	7.0%	Not Provided	Not Provided	14.0%	13.7%	12.4%	12.4%
Tuktoyaktuk	303	Not Provided	Not Provided	452	404	480	485
	7.0%	Not Provided	Not Provided	10.0%	9.2%	10.6%	10.6%
Fort McPherson	174	Not Provided	Not Provided	170	160	146	144
	4.9%	Not Provided	Not Provided	4.9%	4.7%	4.2%	4.2%
Aklavik	102	Not Provided	Not Provided	92	123	158	158
	3.6%	Not Provided	Not Provided	3.1%	4.2%	5.7%	5.7%
Deline	182	Not Provided	Not Provided	251	230	242	243
	7.0%	Not Provided	Not Provided	9.2%	8.5%	9.1%	9.1%
Fort Good Hope	60	Not Provided	Not Provided	145	187	153	154
	2.3%	Not Provided	Not Provided	4.9%	6.6%	5.4%	5.4%
Tulita	112	Not Provided	Not Provided	197	170	181	183
	5.3%	Not Provided	Not Provided	8.8%	7.8%	8.3%	8.3%
Paulatuk	69	Not Provided	Not Provided	107	69	109	112
	7.0%	Not Provided	Not Provided	7.5%	5.1%	8.2%	8.3%
Sachs Harbour	38	Not Provided	Not Provided	70	68	42	41
	3.6%	Not Provided	Not Provided	7.1%	7.1%	4.5%	4.5%
Tsiigehtchic	47	Not Provided	Not Provided	62	47	55	57
	6.1%	Not Provided	Not Provided	7.4%	5.6%	6.6%	6.6%
Colville Lake	15	Not Provided	Not Provided	49	35	54	55
	7.0%	Not Provided	Not Provided	15.5%	11.0%	16.2%	16.3%
Ulukhaktok	133	Not Provided	Not Provided	119	111	104	110
	7.0%	Not Provided	Not Provided	6.1%	5.5%	5.5%	5.5%
Thermal	**4808**	**Not Provided**	**Not Provided**	**5208**	**5232**	**5813**	**5886**
	6.3%	**Not Provided**	**Not Provided**	**6.5%**	**6.5%**	**7.2%**	**7.2%**
Overall	**19,953**	**24,807**	**Not Provided**	**24,367**	**19,137**	**19,197**	**20,283**
	5.7%	**Not Provided**	**Not Provided**	**6.5%**	**5.6%**	**5.7%**	**5.9%**

In the 01/03 Settlement, losses had been capped at 7%. Forecast losses for 06/07 and 07/08 represent the full uncapped losses on each system and are calculated as a rolling average of losses over the previous five years.

Overall the total forecast corporate-wide losses for 06/07 and 07/08 are approximately the same as the 01/03 Settlement. A slight increase in losses from 06/07 to 07/08 is due to modest sales growth.

According to NTPC, the Taltson system experiences substantial losses due to the long and lightly-loaded transmission system. This has a mitigating effect on overall loss reduction, however since the losses on Taltson are supplied by surplus hydro, there is no net cost to the losses on that system.

Outside of Taltson, NTPC asserts that losses have declined in both absolute and relative terms since the 01/03 Settlement which reflects NTPC's continuing efforts to reduce the overall level of line losses. However some communities still have losses higher than 7% despite NTPC's best efforts to reduce loss levels.

According to NTPC, the losses in the thermal communities are now confirmed by over a decade of experience. They are not anomalies and should be included in the calculation of the revenue requirement.

In BR.NTPC-5(a), NTPC provided the following explanation as to why losses are high in some communities.

> "The following communities have forecast losses as a percentage of generation to be greater than 7% for the two test years: Wha Ti, Fort Liard, Nahanni Butte, Jean Marie River, Norman Wells, Tuktoyaktuk, Deline, Tulita, Paulatuk, and Colville Lake.

Metering problems have been identified in Jean Marie River, Nahanni Butte and Colville Lake and steps have been taken to correct these problems.

Losses represented in Appendix A include losses from distribution transformers, conductors and the residual difference between metered generation and metered consumption. Factors that impact losses include, metering accuracy, conductor size relative to load, transformer size relative to load, distance from the source of generation to the delivery point.

As these communities have grown, customer loads are getting further from the generation source and the loads on feeders are increasing. In particular, Norman Wells and Tuktoyaktuk, losses are negatively impacted by the significant distance from the generation source. In addition, historical assets were not necessarily built with a view to reduce losses however as these assets are changed out over time, the Corporation considers current and future loads in assessing the best match for voltage, conductor and transformers in order to reduce future losses.

No other cost effective steps or investigations have been identified at this time to reduce losses."

NTPC provided further explanation in its argument.

"Except for Taltson, the Corporation's line losses as a percentage of sales have declined from 6.01% to 4.95% since the last GRA. In the case of Taltson, percentage losses are high reflecting the unavoidable characteristics of substantial and lightly loaded transmission, and in any event do not drive costs in the Revenue Requirement as they are served by surplus hydro.

BR.NTPC-5 requested NTPC to provide an explanation as to communities where losses were higher than 7%. The 10 communities listed reflect basically the same communities that have had losses in the higher end of the range going back to the Board's Decision 9-93 and that investigations have been done over a long period of time on these communities. While generic approaches that can be employed to reduce line losses (such as reconductoring or voltage conversion) are expensive and not practical in these cases, "[n]o other cost effective steps or investigations have been identified at this time to reduce losses". Consequently, NTPC submits that the line losses indicated in the GRA are a reasonable, valid and justified

> cost of operating its systems, and as such should be approved the Board as part of calculating the NTPC's Revenue Requirement.
>
> Ms. Goucher noted in her opening comments an error in the calculation of the line losses for Norman Wells. The Corporation proposes that this error be corrected (line losses reduced and consequently Revenue Requirement reduced) in its final GRA refiling. (NTPC Argument, p. 10, *ll*. 4 – 20)

As stated at the hearing, NTPC expects that the Norman Wells losses will be reduced from the 12.4% in the application to about 10%.

Views of the Board

Losses are comprised of two components: electrical losses and non-electrical losses, a major part of which is unbilled energy at year-end. The Board considers if there is variation in the cycle meter reading dates, the amount of unbilled energy may vary from year to year.

The Board is of the view that electrical loss data is similar to the use of fuel efficiency data in that both data sets are measurements of the efficiency of a particular portion of the electrical system. Given that both data sets are efficiency measures, it is the Board's view that electrical losses can and should be forecast with the 3-year 3:2:1 weighting procedure used for fuel efficiency forecasts.

While the 3-year 3:2:1 weighting system is preferred by the Board for dealing with electrical losses, the Board recognizes that this method might not be suitable for application to non-electrical losses. As well, the Board recognizes that there is insufficient evidence in this proceeding to effectively separate electrical losses and non-electrical losses.

The Board directs that, in the next GRA, NTPC is to include an examination of the pros and cons of separating losses into its two components (electrical losses and non-electrical losses) which would allow the electrical losses to be forecast using the same method as for fuel efficiencies while non-electrical losses could still be forecast using the 5-year rolling average method.

While the forecast 06/07 and 07/08 corporate-wide losses are approximately the same as the 01/03 Settlement, in the absence of many of the actual 02/03 losses, it is not possible for the Board to determine if any meaningful improvements in losses have been made by NTPC in many of the communities.

That being said, the Board is not satisfied with the level of effort or the results achieved by NTPC in reducing the high losses in some communities. While the high losses in Jean Marie River and Colville Lake might not be anomalies, the Board does not consider losses of 19.0% and 16.3% to be reasonable.

As part of the 01/03 Settlement, the Board approved a 7% cap on losses. It is the Board’s view that the continuation of this cap is necessary to protect consumers in high loss communities. The Board directs NTPC, as part of its Phase 1 refiling, to apply a 7% cap on losses.

It is the Board’s view that the analysis of this issue would have been simplified had the data shown in Table 5.3 been provided in such a format as part of the Phase 1 application. The Board directs NTPC, in the next GRA, to provide an updated version of Table 5.3 that includes the forecast and actual losses for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.

5.2.2 Station Service

Station service data, which has been provided over the course of this review, is compiled in Table 5.4. The data is drawn from the Phase 1 Application (Schedules 2.1, 2.2 and 2.3, and Schedules A.1 to A.27) and information requests (TGC.NTPC-32 and HC.NTPC-9(g)). The station service as a percentage of generation was calculated by the Board from the information provided in these same sources where total generation was provided.

Table 5.4 – Station Service (MWh and % of Generation)

	02/03 Settlement	**02/03 Actual**	**03/04 Actual**	**04/05 Actual**	**05/06 Actual**	**06/07 Forecast**	**07/08 Forecast**
Behchoko	Not Provided						
Dettah	Not Provided						
Snare	5828	5619	5991	7006	6291	5982	6137
	2.8%	2.7%	2.9%	3.1%	3.2%	3.1%	3.1%
Fort Resolution	Not Provided	Not Provided	Not Provided	104	111	111	111
	Not Provided	Not Provided	Not Provided	3.7%	4.1%	4.1%	4.2%
Fort Smith	2660	916	833	788	690	690	690
	9.0%	4.1%	3.8%	3.5%	3.2%	3.2%	3.2%
Taltson	2660	2182	1924	1037	1665	1665	1665
	4.2%	3.4%	3.1%	1.6%	2.6%	2.5%	2.5%
Hydro	**8488**	**Not Provided**	**Not Provided**	**8044**	**7956**	**7647**	**7802**
	3.1%	**Not Provided**	**Not Provided**	**2.7%**	**3.0%**	**3.0%**	**3.0%**
Wha Ti	32.6	Not Provided	Not Provided	23	23	23	23
	1.8%	Not Provided	Not Provided	1.3%	1.3%	1.3%	1.3%
Gameti	52	Not Provided	Not Provided	64	85	85	85
	5.5%	Not Provided	Not Provided	6.6%	8.6%	8.7%	8.7%
Lutsel K'e	103	Not Provided	Not Provided	87	96	96	96
	6.8%	Not Provided	Not Provided	5.5%	6.1%	6.0%	5.9%
Fort Simpson	320	261	302	263	231	231	231
	4.0%	Not Provided	Not Provided	3.3%	2.9%	2.8%	2.8%
Fort Liard	56	61	44	45	33	33	33
	1.5%	Not Provided	Not Provided	1.6%	1.2%	1.2%	1.2%
Wrigley	30	Not Provided	Not Provided	24	27	27	27
	3.6%	Not Provided	Not Provided	3.1%	3.7%	3.7%	4.0%
Nahanni Butte	36	Not Provided	Not Provided	28	33	33	33
	8.7%	Not Provided	Not Provided	7.1%	8.0%	8.4%	8.8%
Jean Marie River	37	Not Provided	Not Provided	31	31	31	31
	13.5%	Not Provided	Not Provided	9.5%	10.2%	9.3%	9.1%
Inuvik	1422	1607	1687	1783	1612	1612	1612
	4.9%	Not Provided	Not Provided	5.8%	5.2%	5.2%	5.1%
Norman Wells	152	Not Provided	Not Provided	67	101	101	101
	2.1%	Not Provided	Not Provided	0.7%	1.1%	1.1%	1.1%

Tuktoyaktuk	208	Not Provided	Not Provided	198	226	226	226
	4.8%	Not Provided	Not Provided	4.4%	5.2%	5.0%	4.9%
Fort McPherson	231	Not Provided	Not Provided	23	153	153	153
	6.5%	Not Provided	Not Provided	0.7%	4.5%	4.4%	4.5%
Aklavik	102	Not Provided	Not Provided	127	117	117	117
	3.6%	Not Provided	Not Provided	4.4%	4.0%	4.2%	4.2%
Deline	88	Not Provided	Not Provided	58	56	56	56
	3.4%	Not Provided	Not Provided	2.1%	2.1%	2.1%	2.1%
Fort Good Hope	139	Not Provided	Not Provided	126	76	76	76
	5.3%	Not Provided	Not Provided	4.3%	2.7%	2.7%	2.6%
Tulita	172	Not Provided	Not Provided	127	122	122	122
	8.1%	Not Provided	Not Provided	5.6%	5.6%	5.6%	5.5%
Paulatuk	86	Not Provided	Not Provided	50	53	53	53
	8.7%	Not Provided	Not Provided	3.5%	3.9%	4.0%	3.9%
Sachs Harbour	97	Not Provided	Not Provided	104	96	96	96
	9.1%	Not Provided	Not Provided	10.5%	9.9%	10.3%	10.6%
Tsiigehtchic	39	Not Provided	Not Provided	44	39	39	39
	5.1%	Not Provided	Not Provided	5.2%	4.7%	4.7%	4.5%
Colville Lake	35	Not Provided	Not Provided	4	2	2	2
	15.8%	Not Provided	Not Provided	1.3%	0.6%	0.6%	0.6%
Ulukhaktok	13371	Not Provided	Not Provided	68	62	62	62
	3.7%	Not Provided	Not Provided	3.5%	3.1%	3.3%	3.1%
Thermal	**3511**	**Not Provided**	**Not Provided**	**3344**	**3274**	**3274**	**3274**
	4.6%	**Not Provided**	**Not Provided**	**4.1%**	**4.1%**	**4.1%**	**4.0%**
Overall	**11,999**	**11,164**	**Not Provided**	**11,387**	**11,231**	**10,921**	**11,076**
	3.4%	**Not Provided**	**Not Provided**	**3.1%**	**3.3%**	**3.2%**	**3.2%**

The forecast overall 06/07 station service has decreased from the 01/03 Settlement, both in absolute terms and as a percentage of sales. There has been a material increase however at the Jackfish diesel plant. The remaining communities are forecast by NTPC to achieve stable station service loads or reductions compared to 02/03.

With the decreased use of the diesel engines at Jackfish, the residual heat from the engines is no longer sufficient to provide heat to the plant. Surplus hydro is now used to heat the plant with electric heaters. It is NTPC’s position that the higher station service at Jackfish through the use of surplus hydro is a benefit to ratepayers as it avoids the use of more expensive heating oil.

The station service forecasts are set equal to the station service for the previous year with adjustments made where needed based on specific knowledge of plant requirement changes. The rationale for this approach is that station service normally doesn’t change unless there are material changes in a plant’s systems or structure.

As for station service targets, NTPC explained its approach in the Corporation 2005/06 Greenhouse Gas Report, which was attached to TGC.NTPC-13(a).

> “By diligently monitoring facility statistics, NTPC is able to identify sites where station service requirements are in excess of acceptable levels. NTPC set a target for each facility to achieve and maintain a station service less than or equal to 5% of its total generation. NTPC will continue to monitor station service and work to reduce it at the seven plants still exceeding the 5% target while maintaining all other site station service percentages below the target.” (TGC.NTPC-13(a) attachment, p. 14)

The Greenhouse Gas Report also described NTPC’s approach and techniques for reducing station service.

> “NTPC is continuously investigating ways to reduce its own consumption of power. Some of the equipment and design improvements utilized to reduce station service at our plants include:
>
> - replacement of in-plant electric space heating with residual heat from engine jacket water systems;
> - replacement of engine electric block heaters with residual heat circuits that utilize jacket water heat from operating engines;
> - replacement of inefficient lighting;
> - installation of separate lighting circuits so that only specific lights are on at certain times;
> - installation of variable frequency drives on radiators; and
> - installation of photo sensors on all outside lighting.
>
> Station service reductions have also come through the education and resulting heightened awareness of plant personnel. Small measures are highlighted, such as turning off lights when plants are unattended, turning heaters down or off when not required, and ensuring that any pipes or other equipment that require heat tracing during winter months are shut-off

during spring and summer months." (TGC.NTPC-13(a) attachment, p. 13 - 14)

NTPC states that it has significantly reduced station service as a percentage of generation over the last several years. It will continue to monitor station service and work to reduce it where cost effective.

At the hearing, the TGC questioned NTPC on why the station service target was set at 5%. NTPC responded that 5% was simply chosen by the operations staff as a reasonable target given the range of actual station service that was being used in the various communities.

> "MR. AZAD MERANI: …
>
> You -- you really don't have any – any better explanation for why 5 percent is more appropriate than a lower number? You just picked it because that was the target that you guys thought was a reasonable target?
>
> MR. STEPHEN KERR: The -- I guess you -- you are correct. Five percent was a number that the Power Corporation, its operation staff set…" (Tr. Vol. II, p. 48, *ll*. 2 – 11)

When asked by the TGC why some of the smaller communities had station service in excess of the 5% target, NTPC responded that there is certain amount of station service inherent in all of the plants but the only specific reason provided was that Jean Marie River has an office that is separate from the power plant and that uses electric heat. NTPC then reverted to a discussion of what it has done to reduce station service rather than providing direct answers to the question that had been asked.

The TGC questioned NTPC on what it would do if the Board were to establish a target lower than 5%.

> "MR. STEPHEN KERR: I guess for the Power Corporation to try to achieve something -- some target, arbitrary target, that would be imposed would probably take a lot of money and investment, particularly, in some of the older plants to try and go in and retrofit those facilities; that would mean fairly significant capital dollars in some place for probably minimal return.
>
> So I'll -- for us to undertake that, we could certainly attempt it, but at the end of the day I'm not sure it would be in the best interest of our customers." (Tr. Vol. II, p. 49, *ll*. 11 – 21)

TGC summarized its views on this matter in its argument.

> "NTPC's target station service loss ratio of 5% is arbitrary and unrealistic; since 1990/91, it has been able to achieve a reduction in the overall average station service losses from 9.0% to 4.4% in 2005/06, a reduction of some 51%. NTPC should provide evidence, at its next GRA, as to why it cannot, and has not been able to reduce station service losses to 1-2% of total generation experienced in several communities in 2005/06. Further, to the extent it is able to reduce station service loss ratios below those approved in this GRA, a deferral account should be set up to allow any savings, net of any incremental costs not included in the 2006/07 and 2007/2008 Revenue Requirements, to be flowed through to customers in the next GRA." (TGC Argument, p. 30)

NTPC submitted in its argument that:

> "No evidence was submitted by any intervenor challenging NTPC's station service or line loss forecasts. Consequently, NTPC submits that the station service, line losses and overall load forecast provided in Chapter 2 and Appendix A of the Application is reasonable and should be approved by the Board." (NTPC Argument, p. 11, *ll*. 29 – 32)

In its reply, NTPC directly addressed the recommendations from the TGC. On lowering the 5% target, NTPC cautions that there are limited economic opportunities to improve station service. NTPC also opposes the creation of a station service deferral account due to the hypothetical nature of potential station service projects and also due to the fact that station service projects are a normal component of NTPC costs with investments in capital improvements to reduce station service loads capitalized as with any other capital asset.

Views of the Board

The Board is of the view that station service data is similar to the use of fuel efficiency data in that both data sets are measurements of the efficiency of a particular portion of the electrical system. Given that both data sets are efficiency measures, it is the Board's view that they can and should be forecast in a similar manner. NTPC explains that station service forecasts are set equal to the station service for the previous year with adjustments made where needed based on specific knowledge of plant requirement changes. However, NTPC does not provide any justification for using this procedure as opposed to an alternative such as the 3-year 3:2:1 weighting procedure already used for fuel efficiency forecasts.

The Board directs NTPC that, in its Phase 1 refiling, station service is to be calculated using the same procedure used for fuel efficiencies. Forecast station service is to be calculated using 3 years of actual data with a weighting of "3" given to the lowest station service year, a weighting of "2" given to the middle station service year and a weighting of "1" given to the highest station service year. Consistent with its directions respecting fuel efficiencies, the Board directs NTPC to give due weight to the first test year station service forecasts in order to calculate the second test year station service forecasts, in the next GRA.

While the forecast 06/07 and 07/08 corporate-wide station service is a slight improvement over the 01/03 Settlement, in the absence of many of the actual 02/03 amounts, it is not possible for the Board to determine if any meaningful improvements have been made by NTPC in many of the communities over this time period. Over the longer term, however, it is apparent that significant improvements have been made in station service levels.

While the Board is encouraged by the improvements made in station service, the Board is still concerned that, in some communities, station service is still too high. In particular, the Board finds that station service levels in Gameti, Nahanni Butte, Jean Marie River and Sachs Harbour are unreasonably high.

Given the high station service in some communities, it is the Board's view that a station service percentage cap is necessary to protect consumers in these communities. The Board directs NTPC, in its Phase 1 refiling, to apply a 5% cap on station service as a percentage of generation.

It is the Board's view that the analysis of this issue would have been simplified had the data shown in Table 5.4 been provided in such a format as part of the Phase 1 application. The Board directs NTPC, in the next GRA, to provide an updated version of Table 5.4 that includes the forecast and actual station service for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.

With the imposition of the station service percentage cap, the Board does not see any need to create a station service deferral account. However, the Board does direct NTPC to provide a more detailed analysis of station service levels and potential reductions at its next GRA.

5.3 Fuel Pricing in Inuvik

The TGC expressed concern with the 15-year contract that NTPC has for the supply of natural gas in Inuvik. Specifically, the TGC is concerned that the contract indexes the price of natural gas to local diesel prices rather than world gas markets. The NTPC provided an explanation in its response to TGC.NTPC-18(a).

> "The terms of the natural gas agreement dictate that the price be based on the Edmonton average unbranded regular diesel price as seen in Bloomberg Oil Buyers Guide. This is because natural gas price indices have no relevance to the gas system in Inuvik, as there is no way of getting the gas from lnuvik to a North American market. The value of gas in lnuvik is as a displacement to diesel fuel, and as a result diesel-linked pricing is the appropriate benchmark for both NTPC and the vendor."

In its Argument, the TGC provided the following analysis and recommendation.

> "NTPC also states it cannot change the index to an AECO-C or NYMEX gas price index because the contract with the Town of Inuvik is for a 15-year term, and "so changing the rules or underlying principles of the contract at this point is not an option. However, at renewal time we would be open to those discussions."
>
> The TGC submits NTPC's reluctance to review the terms of the contract on a bilateral basis is difficult to understand. As the price paid for natural gas, whether tied to a diesel index or gas index, is eventually part of the Fuel Stabilization Fund for Inuvik, there should be no impact on the Corporation's bottom line. That is, any cost or savings that arise from the use of an alternative index is to the account of customers in Inuvik, not the shareholder.
>
> As to NTPC's argument that a gas pricing index is irrelevant because of a lack of physical connection, the TGC submit to the extent the objective is to set a reasonable price, physical connection is an irrelevant consideration. What is relevant is that gas prices be tied to a gas index;

> there is no evidence that gas prices have any nexus to the world diesel prices.
>
> As such, the TGC submit the Board direct the Corporation to commence discussions with the Town of Inuvik with a view of determining if the use of a gas price index such as the AECO-C or NYMEX, can provide benefits (in terms of cost savings, or additional stability) to customers in Inuvik. In our view, as long as two parties are willing and agreeable, any contractual arrangement can be changed; hence, there is no need to wait, as NTPC asserts, for the 15-year contract term to expire." (TGC Argument, p. 19 – 20)

The NTPC responded to this recommendation in its reply.

> "The TGC requests that the Board direct the Corporation to commence discussions with the Town of Inuvik respecting the use of another gas price index. That request is supported by the statement that "…the contract with the Town of Inuvik is for a 15-year term…" and the TGCs' apparent misunderstanding that the Town of Inuvik is a party to the Inuvik Gas Sale Agreement. The Town of Inuvik is not, in fact, a party to that agreement. Rather, the Inuvik Gas Sales Agreement is an agreement among Ikhil Resource Ltd., Altagas Marketing Inc. and IPL Holdings Inc., and the Corporation.
>
> Recognizing the actual counterparties to the Inuvik Gas Sale Agreement, the TGC request amounts to a suggestion that the Corporation should break a contract negotiated in good faith among the above noted parties. That suggestion is simply unreasonable, particularly in the context of a contract that has provided substantial benefits to the Town of Inuvik. For example, the Inuvik Gas Sales Agreement has enabled savings related to the Inuvik 3rd engine of over $200,000 in 2006/07 alone. While Ms. Goucher agreed to consult with the Town of Inuvik at the time the agreement is up for renewal, any suggestion that NTPC should break the contract prior to renewal is untenable and should be summarily dismissed by the Board." (NTPC Reply, p. 16, *ll*. 9 – 23)

Views of the Board

The Board does not agree with NTPC's characterization that the TGC recommendation would require the NTPC to "break a contract". As pointed out by the TGC, the parties to a contract can review the terms of the contract and could potentially agree to alter them. This is simply a review which could lead to an amendment. Furthermore, it is clear that the TGC reference to the Town of Inuvik was a mistake which does not detract from their argument.

However, while the TGC is correct that changing the indexing mechanism for the price of Inuvik gas would not impact NTPC's bottom-line, if the ratepayers are to receive a benefit from the renegotiation of this contract then it would be the bottom-line of the other contractual parties that would necessarily be negatively impacted. The Board has no evidence of any consideration which could convince the other contractual parties to agree to a change to the contract at this point.

The Board is satisfied with the NTPC commitment that it will examine this issue in the negotiations for the next contract to replace the current 15-year contract.

6. OPERATION AND MAINTENANCE EXPENSES

The operation and maintenance expenses from the previous GRA to the current GRA forecasts are shown in Table 6.1. The data was obtained from Table 3.3 and Schedules 3.1 and 3.2 revised May 16th.

Table 6.1 – Operation and Maintenance Expenses ($000s)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Hydro	Not Provided	Not Provided	Not Provided	Not Provided	Not Provided	13,982	14,540
Thermal	Not Provided	Not Provided	Not Provided	Not Provided	Not Provided	17,002	17,904
Overall	25,780	Not Provided	Not Provided	27,780	28,014	30,984	32,444

NTPC is seeking Board approval for operation and maintenance expenses of $30.984 million in 06/07 and $32.444 million in 07/08. Less corporate donations of $0.103 million in 06/07 and $0.103 million in 07/08, the operation and maintenance expenses included in the revenue requirement each year is $30.881 million and $32.341 million, respectively.

The 4 components of operation and maintenance expenses are:

- Salaries and Wages
- Non-Production Fuel
- Supplies and Services
- Travel and Accommodation

Interveners raised various issues with respect to these 4 components and these issues are discussed in detail in Sections 6.1, 6.2, 6.3 and 6.4.

Subject to the Board's directions in Sections 6.1 to 6.4, NTPC's proposed operation and maintenance expenses for inclusion in the 06/07 and 07/08 revenue requirement are approved by the Board.

6.1 Salaries and Wages

NTPC is seeking approval for its salaries and wages forecast expenses of $17.730 million for 06/07 and $18.552 million for 07/08.

Table 6.2 summarizes the total salaries and wages data provided in the Application (Table 3.3 and Schedules 3.1 and 3.2 revised May 16th) and subsequent material (HC.NTPC-42 and Table BR.NTPC-10(a) revised May 19th).

Table 6.2 – Salaries and Wages ($000s)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Hydro	Not Provided	Not Provided	Not Provided	6,531	Not Provided	7,403	7,832
Thermal	Not Provided	Not Provided	Not Provided	8,499	Not Provided	9,967	10,720
Overall	14,696	15,569	Not Provided	15,030	16,543	17,370	18,552

The salaries and wages expense includes all pay for full time and casual employees as well as related benefits. The $2.674 million increase from the 01/03 Settlement to the 06/07 forecast is a result of increases required by the collective agreements as well as changes in staff complement. Major components of the increase are:

Safety and Environmental Legislation ($0.293 million) – Legislative requirements has forced the addition of three positions.

Bluefish ($0.409 million) – The addition of the Bluefish Generating Station has increased salaries and wages.

Apprenticeship Program ($0.278 million) – NTPC has undertaken an apprenticeship program by adding three new line positions and two journeyman supervisors. The program will be expanded by another $0.633 million in 07/08 by adding two apprentice mechanics and two apprentice electricians.

Job Evaluation ($0.261) – Implementing a new job evaluation program required an increase in salaries and wages.

Outside of these 4 factors, the salaries and wages increase from the 01/03 Settlement to the 06/07 forecast is $1.433 million or 2.4% average annual growth per year. NTPC attributes this residual growth to wage information and the tight labor markets.

The interveners raised concerns with 4 aspects of the salaries and wages expense:

1. Operational Savings from Bluefish
2. Benefits from Automatic Meter Reading ("**AMR**")
3. At-Risk Compensation
4. Apprentice Salaries

These four issues are addressed by the Board in the following sections.

NTPC's salaries and wages forecasts for 06/07 and 07/08 are approved by the Board subject to the Board directions in Sections 6.1.2 and 6.1.3.

6.1.1 Operational Savings from Bluefish

NTPC purchased the Bluefish Generating Station in 2002. The benefits expected by NTPC included avoided diesel generation, reduced future diesel engine replacement at the Jackfish Lake plant, and an increased ability to meet future load growth on the Snare-Yellowknife system.

NTPC states that while Bluefish has resulted in significant reduced overall costs with large savings in diesel fuel use being offset somewhat by increases by the operating and capital costs of Bluefish. In the area of salaries and wages, Bluefish's forecasts are $0.409 million for 06/07 and $0.423 million for 07/08.

The difference between what was forecast for Bluefish at the time of purchase and the forecast for the 2 test years was explored in BR.NTPC-9. The Project Permit forecast salaries and wages for 02/03 and 03/04 as $0.262 million so the 06/07 and 07/08 forecasts represent $0.147 million and $0.161 million increases, respectively. The explanation provided for these increases is:

> "Salaries are analyzed as a group since variations in the allocations of salary costs between labour accounts are a result of a lack of working experience when the project permit was completed in managing the labour needed between operations and maintenance and regular time, overtime or casuals, as well as in managing the Bluefish labour requirements with those at Snare and Jackfish. Compared to the project permit projections, salaries have increased by $145,000. This is a result of more work required than originally expected to maintain the facility coupled with average labour cost increases over the period between 2003/04 and 2006/07." (BR.NTPC-9, p. 1 of 6)

In HC.NTPC-13(g), the HC requested the salaries and wages for Jackfish, Bluefish and Snare for 02/03 through 07/08. NTPC provided the following table:

	2004/05 Actual	**2005/06 Actual**	**2006/07 Forecast**	**2007/08 Forecast**
Jackfish	1,598	1,515	1,646	1,882
Snare	1,057	1,195	1,230	1,271
Bluefish	74	358	409	423
Totals	2,729	3,068	3,284	3,576

> Note: the costs for General & Administration are not tracked separately between Bluefish, Jackfish and Snare, therefore they are all included with costs for Jackfish

The HC pursued this line of questioning at the hearing and again in their argument. The basic thrust of the HC position is that the purchase of the Bluefish Generating Station should have provided reductions in salaries and wages at Jackfish due to the reduced need for diesel generation. When questioned by the HC, NTPC responded that personnel, and therefore their salaries, are deployed across the Snare, Bluefish and Jackfish system on an as-needed basis. Since specific positions are not dedicated to Snare, Bluefish or Jackfish, NTPC cannot provide the information requested by the HC. Across the combined system, the number of positions has been relatively constant with 41 (04/05), 39 (05/06), 39, (06/07) and 41 (07/08). The HC's evaluation of this information was summarized in its argument:

> "…NTPC was requested to provide the positions represented by the salary costs in HC.NTPC-13(g) to determine whether the operating savings as a result of the Bluefish purchase had materialized. NTPC advised that it was unable to make that distinction and could only advise that the number of positions across the Snare system for 2004/05 onward including the two test years were 41, 39, 39 and 41 respectively and that the number of operator positions at Jackfish had been reduced by 5. That information does not demonstrate any labor savings as a result of the Bluefish purchase because those FTE's include system operators for the thermal communities as well." (HC Argument, p. 16)

Given that the information provided by NTPC did not permit a clear calculation of salaries and wages reductions at Jackfish due to Bluefish, the HC recommendation to the Board is:

> "…The Hydro Communities submit absent any demonstrated savings in operating expenses as a result of the Bluefish purchase, the Board should

> maintain Jackfish salaries … at the 2005/06 levels shown in HC.NTPC-13(g)…" (HC Argument, p. 17)

The NTPC countered in its reply:

> "It is clear that at the time of the project permit application, the feasibility of the project did not hinge on achieving any non-diesel fuel operating expense savings. Rather, the project was and continues to be justified on basis of avoided diesel fuel and engine replacement costs. This is clearly demonstrated in the attachment to BR.NTPC-29(k), which indicates that the only variable (meaning O&M, Salaries and Wages, and Supplies and Services) savings from Bluefish included in the project permit application economics was based on 2.5 cents per diesel kW.h displaced. This savings reflects the costs of overhauls and other related savings, such as oil changes at the Jackfish units, which would have otherwise been part of NTPC's revenue requirement over time. In short, in contrast to Hydro Communities' assertions, the purchase of Bluefish was not predicated on saving in Salaries and Wages and Supplies and Services at Jackfish. Despite this, Ms. Goucher noted that the purchase of Bluefish, in combination with changes to the industrial loads on the Snare-Yellowknife system, has allowed NTPC to reduce Jackfish plant operators by five positions, a benefit in excess of those assumed at the time of the Bluefish purchase.
>
> …
>
> The reduction in salaries and wages related to the Bluefish acquisition requested by the Hydro Communities is arbitrary, unsupported by the evidence and should be rejected by the Board. The Corporation addressed this issue in its Written Argument at page 13 and has provided considerable evidence to support the increases in operations and maintenance costs in the test years over the 2005/06 levels. The Corporation submits that these costs are reasonable and should be approved." (NTPC Reply, p. 11)

Views of the Board

The Board agrees with NTPC that the Bluefish purchase was not predicated upon, and might not result in, demonstrated operational savings in salaries and wages at Jackfish. While such savings can and should be sought by NTPC whenever feasible, the Board is satisfied that the salaries and wages forecasts provided by NTPC do not require an adjustment by the Board. The Board will not act upon the recommendation from the HC to maintain the Jackfish salaries and wages at 05/06 levels.

6.1.2 Benefits from Automatic Meter Reading ("AMR")

Appendix C of the Phase 1 GRA described 4 AMR projects:

Date	Location	Project Number	Description	Cost
2004/05 Actual	Norman Wells	3045049	Turtle Meter Reading Conversion	$107,000
2005/06 Actual	Fort Smith	2015157	Turtle Meter Reading Conversion	$206,000
2006/07 Forecast	Fort Simpson	2055090	Turtle Meter Reading Conversion	$150,000
2007/08 Forecast	Ops Support	9905021	Turtle Meter Reading Conversion	$200,000

The Norman Wells, Fort Smith and Fort Simpson projects converted all customers in these communities to meters for the Hunt Technologies Turtle AMR System. NTPC stated that the previous meter system was time-consuming and inefficient and that the technical support had been discontinued. The new meter system allows NTPC to better utilize line personnel. The projects were undertaken for cost savings.

The 2007/08 project, which is listed under Ops Support, is intended to ensure that a funding allocation is in place to enable the continuation of this conversion project in one or two more communities. NTPC is undertaking a review to determine which communities are the most suitable to upgrade.

The Fort Smith project is noted in a couple of locations (Table NTPC.TWU-9 and Table HC.NTPC-64) as being "Partial Close Out", indicating that the actual cost is higher than the 2005/06 actual of $206,000 listed in Appendix C.

For the Fort Simpson project, the alternatives are listed in Table NTPC.TWU-8a as being:

1) Do Nothing
2) Contract meter reading locally
3) Convert meters to the Turtle System

NTPC provided additional details on their projects in BR.NTPC-29(m).

> “In 1996/97 NTPC undertook research and investigated the emerging technologies related to Automatic Meter Reading (AMR). The Hunt Technologies AMR system (Turtle) utilized Power Line Carrier (PLC) to transfer data. This meant that NTPC's existing distribution system could be utilized instead of 3rd party communications (i.e. telephone lines). In this way, the Corporation would eliminate the cost of telephone charges to download information or interrogating the system. The meters could be read remotely without driving or walking the community routes with a radio system.
>
> At that time, the only other PLC based AMR system was TWACS or DCSI, which was much more expensive than the Hunt Technologies system. Other considerations were:
>
> - Hunt Technologies superior design of substation interface between the reading collector and meter transmitter
> - Hunt Technologies could also supply all NTPC's meter needs while others could only supply domestic energy meters
> - Hunt Technologies also had water meter transmitters and NTPC was supplying water to the Town of lnuvik at that time. This also provides the Corporation with the flexibility of potentially offering water meter reading services to other communities in the future.
>
> To date, the installation and utilization of this system has been a success. It has reduced time required to read meters, improves accuracy of meter reads, and reduces administrative time for data entry and significantly reduces billing errors which improves customer relations. Finally, the Turtle meters free up line personnel to take on more meaningful and productive work.

> Prior to the utilization of the AMR system, meter reading costs were approximately $30-$35 per meter per year (depending upon the community). With the AMR system, meter reading costs are $2.00 - $2.50 per meter."

Both the HC and the TGC questioned NTPC on this issue at the hearing. These exchanges were summarized by NTPC in its argument.

> "In 1996/97 NTPC undertook research and investigated the emerging technologies related to Automatic Meter Reading ("AMR"). The Hunt Technologies AMR system (Turtle) used Power Line Carrier to transfer data. This meant that NTPC's existing distribution system could be utilized instead of 3rd party communications. To date, the installation and utilization of the system has been a success. It has reduced time required to read meters, improves accuracy of meter reads, and reduces administrative time for data entry and significantly reduces billing errors which improves customer relations.
>
> The Board requested more information on studies undertaken to justify the Norman Wells AMR project in 2004/05, the Fort Smith AMR project in 2005/06 and the Fort Simpson AMR project forecast for 2006/07. In BR.NTPC-29(m) NTPC provided a series of net-present value analyses that showed all of the projects had positive net preset value under the assumptions both at the time the projects were proposed and using current cost variables.
>
> During the hearing, the TGC's consultant requested more detail with respect to the net preset value analysis undertaken for the Fort Simpson AMR project. The Corporation responded to this request in Undertaking No. 15. Counsel for the Hydro Communities also asked whether there was any reduction in staff levels related to meter reading or administrative data entry, to which Ms. Goucher replied that "…installation of the automatic Turtle meter reading system has allowed us to utilize our line persons for other line-related work, as opposed to meter reading."
>
> The evidence demonstrates that the AMR projects have improved the efficiency of the Corporation's operations and have a net benefit to customers. However, this does not mean that staff positions can be reduced or eliminated as a result of the projects. The Corporation submits

> that costs related to the AMR projects are reasonable and should be approved. (NTPC Argument, p. 51, *ll*. 22 – p, 52, *ll*. 8)

As described in its argument, the HC were concerned that there has been no change in the Fort Smith NTPC staff levels as a result of installing the new AMR with the net result being a rate base addition of $206,000 but no operating savings. The HC argued that if the project is added to rate base then labor costs in Fort Smith should be reduced by $35,000/year so that there is no net impact upon the rate payers due to this project.

In its reply, the NTPC urged the Board to disregard the HC recommendation. NTPC stated that a portion of Fort Smith lineman costs will not be allocated to Fort Smith in the Phase 2 GRA. As well, the elimination of technical support for the previous system necessitated that a new system be installed. The chosen system also provides greater accuracy and reduces billing errors.

In its reply, the HC proposed an alternative recommendation to that provided in its argument.

> "At page 52, NTPC asserts that the AMR projects have improved the efficiency of the Corporation's operations and have a net benefit to customers. This statement assumes there were benefits which is not true. The net present value analysis in BR.NTPC-29(m) indicates a 10-year net present value of $75,000. However, as noted at pages 18-19 of the HC Argument, there are no labor savings because linemen have been redeployed to other areas. The Hydro Communities reiterate that if the $206,000 net rate base addition is approved, then labor costs should be reduced by $35,000 per year so that customers are indifferent. Alternatively, the project should be excluded from rate base until such time as the $35,000 of labor savings can be demonstrated." (HC Reply, p. 23)

Views of the Board

The Board is concerned that it does not have complete and accurate analyses of the costs and benefits of these AMR projects as reflected in the application, which includes the impact on community operating expenses.

The HC argues that NTPC "*assumes there were benefits which is not true*". While the Board does not agree that the asserted benefits have been proven to not be true, the Board does believe that the asserted benefits have not been completely and accurately quantified. By not incorporating the effect of the redeployed linemen (along with justification for this redeployment) in the filed material, it is not possible for the interveners or the Board to properly assess and test the assertions being made by NTPC.

While the HC was only advancing its arguments on behalf of Fort Smith, the Board notes that this issue of redeployment of linemen appears to affect all of the AMR projects. Given that NTPC is asserting that a benefit of these projects are the allocation of linemen costs to outside of the community in which they are based, the economic analyses and cost tracking provided by NTPC should be completed from the perspectives of both NTPC and the specific communities in which these projects have been completed/proposed.

The Board is prepared to approve the addition of these four AMR projects (Project Numbers 3045049, 2015157, 2055090 and 9905021) to NTPC's rate base. However, pending this approval, the Board directs NTPC, as part of the Phase 1 refiling, to provide complete and accurate analyses of the costs and benefits of these projects that incorporate the reasons for and the effects of the redeployment of the linemen. These analyses are to be provided both from the perspective of the individual communities and NTPC.

6.1.3 At-Risk Compensation

There was no mention of at-risk compensation in the Phase 1 Application. At-risk compensation was first mentioned on the record on page 42 of NTPC's 2005/06 Annual Report, which was submitted as an attachment to HC.NTPC-1. At-risk compensation falls under the responsibilities of the NTPC's Board of Director's Compensation Committee. The following description is from the Annual Report.

> "The compensation committee should be responsible for:
>
> (a) reviewing and approving corporate goals and objectives relevant to CEO compensation, evaluating the CEO's performance in light of those corporate goals and objectives, and determining (or making recommendations to the board with respect to) the CEO's compensation level based on this evaluation;
>
> (b) making recommendations to the board with respect to non-CEO officers and director compensations, incentive-compensation plans and equity-based plans; and
>
> (c) reviewing executive compensation disclosure before the issuer publicly discloses this information."

According to the Annual Report, the Compensation Committee should be composed entirely of independent directors. The members of the committee at that time were:

1. Peter Allen – Committee Chairman and Board Member
2. Richard Nerysoo – Board Chairman
3. Leon Courneya – President and CEO

The at-risk compensation system was described in detail in BR.NTPC-10(b&c).

"NTPC's Senior Management (SM) Salaries and At-Risk (performance based component) are set by the Board of Director's Governance and Compensation Committee (Committee) and approved by the Board of Directors with the assistance of outside consultants. NTPC's SM salaries are set in comparison to a group of utilities selected by the Committee as the organizations which NTPC competes with for staff.

The Committee retains Towers Perrin HR Services to perform a detailed survey every 3 years of a group of utilities to compare NTPC Senior Management compensation to for salary and incentive plans. The last detailed survey was prepared in March 2004. In years between detailed surveys an informal review is done to ensure there have been no material changes to Senior Management compensation in the intervening years.

The Corporation cannot release the details of the study as it is considered proprietary information of Towers Perrin. The Committee adopted the process of setting SM salaries based on being within 10% (plus or minus) of the 50th percentile. The survey compares total target cash compensation (salary, plus incentive plan/at risk). The method for setting the salary component of SM salaries has not changed since it was adopted. The comparability of the different sizes (revenues) of the companies in the survey is increased through the use of regression analysis.

The results of the last detailed survey in 2004 found that the President's & CEO's total compensation (salary and incentive) were within the target range. The survey also found that while the salaries for the Directors' positions were within the target range the incentive component of Director's compensation was, in general, below the target range.

The last informal survey completed in November 2006 indicated that at the President & CEO's annul salary increase were competitive with the market the Director level annual salary increases were typically below the competitive market and that NTPC's short term target incentive opportunities were below the competitive market.

The Corporation's incentive plan is considered at risk compensation. The At-Risk plan covers all management and excluded positions currently includes approximately 40 positions. Effective April 1, 2007 excluded employees will no longer be eligible for At-Risk (they will receive overtime instead) and the number of positions in the plan will be approximately 30.

Currently there are 3 components to the plan. For each position's eligible pool, 50% of the potential amount is based on net income targets, 25% is based on the achievement of individual objectives and 25% is based on the achievement of operational targets.

Employees under the plan are eligible to earn At-Risk compensation up to 15% of their salary (excluded and Managers), up to 20% of their salary (Directors), up to 30% of their salary (Vice Presidents) and up to 40% for the President & CEO. The system supports achievement of results by setting financial and operational targets. Performance measurement targets are set for system availability, debt/equity ratio, efficiencies, operating cost per kwh generated, customer service (based on external survey), staff turnover, safety (accident severity, lost time accidents, lost time days), MWh generated per hours worked, hazardous materials spills, employee satisfaction (based on external survey).

Management and excluded employees compensation packages are based on the same principles/objectives as the Senior Management Compensation with the exception of how the salary ranges are determined. Excluded and middle management employees positions have been evaluated using the Hay Methodology of job evaluation.

In order to ensure the Corporation remains compliant with equal pay for work of equal value legislation under the Public Service Act, salary ranges are based on the formulas used to determine the bargaining unit salary scale. Excluded employees and Managers do not currently receive overtime. At-Risk compensation is provided in part to recognize an employee for the extra time and effort employees put in to achieve Corporate and individual objectives. Effective April 1, 2007 excluded employees' compensation package is being adjusted to be similar to that of bargaining unit employees. Excluded employees will be eligible to receive overtime and other leave entitlements provided to unionized employees to ensure compliance with equal pay for work of equal value legislation. Management employees will continue to receive at-risk compensation and are not entitled to overtime. At-Risk payments are non-pensionable.

The Corporation does not have a long-term incentive plan.”

Table BR.NTPC-10(a) provided the following at-risk compensation amounts:

- 2002/03 GRA Forecast $586,000

- 2002/03 Actual $608,000
- 2004/05 Actual $547,000
- 2005/06 Actual $595,000
- 2006/07 GRA Forecast $540,000
- 2007/08 GRA Forecast $558,000

The Community of Behchoko suggested in its letter that a clear bonus structure, as well as performance benchmarks tied to levels of service, should form part of the executive compensation model and that the model should be publicly available.

In its argument, NTPC submitted that, given the evidence on the record, its forecast salary and wage expenses in the test years, including at-risk compensation, are reasonable and necessary, and should be approved.

The HC argued that since the Towers Perrin review is considered proprietary and was not filed before the Board, no evidentiary value can be placed on whether or not the total target cash compensation is within 10% of the 50th percentile as adopted by the Governance and Compensation Committee. Nor can any weight be attributed to the informal internal reviews, the last of which was conducted in November 2006, as they are directly linked to the Towers Perrin review.

During HC questioning at the hearing, NTPC confirmed that the 50% of the potential amount that is based on net income targets is based on the rate of return on equity on the regulated business. In argument, the HC took the following position:

> "…Although the Hydro Communities are not opposed to incentive pay, this component is of primary concern because it results in and is motivated

> almost exclusively by benefits to shareholders rather than benefits to customers. This component of the at-risk pay provides perverse incentives to staff, in that cutting service levels may be used to improve the bottom line. For example, deferring maintenance, deferring brushing or charging an engine overhaul or repair to a deferral account may improve the bottom line to the benefit of shareholders and management through at-risk compensation, but customers would be faced with higher costs in the future. Any costs related to improvement of net earnings should be borne by the shareholders who will benefit, not by customers." (HC Argument, p. 21 – 22)

Although it did not cite any decisions, the HC asserted that the Alberta Energy and Utilities Board has consistently disallowed that portion of at-risk or variable pay that is related to or is a function of earnings.

The HC submitted that the achievement of higher earnings will not necessarily translate to improved efficiency to customers and in fact may well have the opposite effect and therefore the 50% of at-risk pay that is a function of net income targets should be excluded from the revenue requirement. Accordingly, the HC submitted that salaries and wages should be reduced by $270,000 and $279,000 respectively in the test years.

For the 25% of at-risk compensation based on individual objectives, the HC seemed to express some concern that these objectives could also relate to financial performance but did not provide any recommendations to the Board.

For the 25% based on operational objectives, the HC consider that for the most part, these objectives would primarily be to the long-term benefit of customers.

NTPC replied that that the Towers Perrin study was not provided because Towers Perrin refused the Corporation's request to file it in this proceeding. In

NTPC's view, however, there is sufficient evidence on the record for the Board and that the HC claim regarding the Towers Perrin study should be disregarded.

Regarding the HC's recommendation that the 50% of at-risk compensation related to net income be disallowed, the NTPC responded as follows.

> "Regarding the Hydro Communities speculation about managements' actions, it is important to recognize that net income objectives are balanced with personal objectives that ensure an on-going benefit to customers by maintaining service levels (through, among other things, efficiency gains, customer satisfaction and employee satisfaction) or avoided costs (such as avoided labour disputes in the event that a collective bargaining agreement is not reached)…" (NTPC Reply, p. 13, *ll*. 1 - 5)

NTPC went on to state the following.

> "Further, if NTPC's managers strive to ensure earnings objectives are met (which by necessity means some combination of lower costs due to efficiencies, or higher revenues), it is in fact customers who will benefit in longer run from lower rates than would otherwise be required, or avoided rate increases and deferred rate cases.
>
> In any event, there is no evidence on the record to suggest that NTPC employees act in the manner described by the Hydro Communities to impair customer service to the benefit of the shareholder. If the Hydro Communities' speculation were true, one would see the performance targets not being met. For example, if management cut costs related to maintenance programs, one would expect problems with safety, reliability, customer service and employee satisfaction. That has not been the case.
>
> There is evidence, however, that the actual amounts paid out by the Corporation as part of the at-risk compensation program have typically been higher than the amounts included in the Corporation's revenue requirement. This means that a portion of the actual costs of the at-risk compensation program is in fact already borne by the shareholder and not by ratepayers. Further, at-risk compensation avoids having to pay overtime – the avoided cost of paying overtime instead of at-risk

> compensation for all positions excluding the Officers of the Corporation is estimated at $425,000.
>
> Lastly, while the Hydro Communities states that the "[t]he Alberta Energy and Utilities Board has consistently disallowed that portion of at risk or variable pay that is related to or is a function of earnings" and lists a number of public utilities, it does not provide any references to regulatory authorities in support of its claim.
>
> NTPC is a regulated entity that must submit its revenue requirement to the review of the PUB and intervenors. The costs included with respect to the at-risk compensation program are typical of such programs for other utilities, are reasonable and should be approved." (NTPC Reply, p. 14, *ll*. 11 - 34)

TGC stated in its reply that it was in agreement with the position taken by the HC in its argument.

Views of the Board

The objective of the Towers Perrin review was to compare NTPC's executive compensation program to other utilities, with NTPC's Governance and Compensation Committee having established a total target cash compensation that is within 10% of the 50^{th} percentile of the other utilities. The Board agrees with the HC that since the Towers Perrin review is not in evidence before the Board, the Board cannot apply any weight to the review when making its decision.

However, the HC has not provided any recommendations or evidence for the Board to use in evaluating the target established by NTPC. The HC does not dispute the 10% of the 50^{th} percentile as being a suitable target for NTPC. Nor did the HC provide any evidence on other utilities' compensation programs. As noted by the HC during questioning, Towers Perrin has provided information in several proceedings in Alberta. It is the Board's view that the HC could have filed this information from other proceedings before the Board.

It is the Board's view that it has no evidence or reason upon which to dispute the NTPC's total target cash compensation range of 10% of the 50th percentile as being acceptable for NTPC.

While the range is not in dispute, what is in dispute is which party should pay for the at-risk compensation: the shareholders or the ratepayers. It is the view of the Board that any at-risk compensation that is included in the revenue requirement should result in clear benefits to customers.

The Board notes that under the Corporation's at-risk compensation program, 50% of the potential compensation amount is based on net income targets, 25% is based on the achievement of individual objectives and 25% is based on the achievement of operational targets.

The 50% of NTPC's at-risk compensation, which is based on net income, is based on the return on equity of the regulated business. The Board agrees with the HC that the potential exists for management to improve net income, and hence increase at-risk compensation, in manner that is detrimental to the ratepayers and exclusively to the benefit of the shareholders.

While NTPC argues that there is no evidence of this occurring, the Board is of the view that no such evidence is necessary for the Board to take action as it is the compensation model that is at question, not any specific actions of management. It is the Board's view that an at-risk compensation model that allows for actions that benefit the shareholders, but not the ratepayers, is not appropriate in NTPC's regulated business.

The Board is also concerned that the 50% based on net income sets up a no-win situation for ratepayers and a no-lose situation for the shareholders.

1) If the net income targets are met, that is a benefit to the shareholders and the at-risk compensation is paid out of money collected from the revenue requirement. However, there is no certainty that there was any benefit for the ratepayers.

2) If the net income targets are not met, the at-risk compensation is not paid but the shareholders retain those dollars collected for that purpose from the ratepayers.

Both ways, the shareholders come out ahead and the ratepayers come out behind.

The Board is also concerned about the entire at-risk compensation program based upon NTPC's statement in the following exchange.

> "MR. TOM MARRIOTT: …What happens to money that is budgeted for this program but not paid out in a given year?
>
> MS. JUDITH GOUCHER: The ***amounts paid out have typically always been higher than what's included in rates***, so I have no knowledge of what would have occurred had the amounts not have been paid out other than it would have been a -- been an expense not incurred." (emphasis added) (Tr. Vol. I, p. 167, *ll*. 11 - 20)

It is the view of the Board that if the ratepayers are to contribute to an at-risk compensation program for senior management, then that compensation should truly be "at-risk" by setting sufficiently demanding targets that are not routinely met. If, as stated by Ms. Goucher, the amounts paid out are always higher than budgeted in the rates, then where is the risk for the senior management from the perspective of the ratepayers? If the targets are being set so low as to ensure that the at-risk compensation is always being paid then the Board fails to see where the incentive lies for management to strive to improve performance. Apparently, the at-risk compensation program is merely base pay in another form.

The Board considers the at-risk compensation to be included in revenue requirement should result in clear benefits to customers. Therefore, in addition to giving weight to achievement of operational targets and individual objectives, consideration may also be given to designing the program to incent efficient planning and execution of capital projects, efficient management of the deferral accounts such as the overhaul deferral account and achievement of safety, reliability and customer satisfaction targets. The Board recognizes some of these targets might presently be part of the operational or individual targets. However, the Board considers greater transparency with respect to the operation of these incentive schemes would be useful in future proceedings.

The Board is also concerned that NTPC has exhibited questionable corporate governance by including Mr. Leon Courneya, the President and CEO and the only non-independent Director, as a member of the Governance and Compensation Committee. This Committee is responsible for evaluating the CEO’s performance and approving the at-risk compensation model and payments to the CEO and other senior management. As noted by NTPC in its Annual Report, this Committee should be exclusively made up of independent directors however Mr. Courneya for some reason is a member of the Committee.

In light of its various concerns, the Board directs NTPC to:

1) Remove the 50% net income component of its at-risk compensation program from the revenue requirement calculations for NTPC's regulated business. For 06/07, the amount is $270,000 and, for 07/08, the amount is $279,000;

2) Ensure that the Governance and Compensation Committee is exclusively made up of independent directors; and

3) Undertake a comprehensive review of the at-risk compensation program; make any necessary changes in light of the concerns expressed by the Board and report back to the Board in the next Phase 1 GRA.

6.1.4 Apprentice Salaries

NTPC views the apprenticeship program as key to ensuring that the Corporation has qualified, highly skilled employees in these positions at a time when workers in these fields are in high demand.

TGC.NTPC-36 identifies that 6 line positions were added in 04/05, 1 line position in 06/07, two journeyman supervisors in 06/07 and 2 apprentice mechanics and 2 apprentice linemen in 07/08.

As already mentioned, the apprenticeship program has driven a $0.278 million increase in salaries and wages from the 01/03 Settlement to the 06/07 forecast. A further $0.633 million is required for the 07/08 forecast.

According to TGC.NTPC-36, the 4 new apprentice positions in 07/08 will cost $490,000 with another $112,000 required for the two journeyman supervisors that were added in 06/07.

In its argument, the HC took issue with the $490,000 required in 07/08 for the 4 new apprentice positions. HC stated:

> "However, NTPC did note that it was adding 4 apprentice positions in 2007/08 at a cost of $490,000 for salaries and benefits. Based on the average union salary of $71,800, the Hydro Communities consider this amount (average of $122,500) is apparently an error and should conservatively be reduced to $71,800 per position, a reduction in salaries and wages of $203,000." (HC Argument, p. 15)

The TGC stated in its reply that it agreed with the argument presented by the HC on salaries and wages.

NTPC responded to the HC recommendation in its reply:

> "Counsel for the Hydro Communities reviewed the forecast of $122,500 on average for the four apprentice positions with Ms. Goucher, who indicated it was not an error. While the average base salary for a union employee is indeed $71,800 for 2007/08, this figure does not include other aspects of the total salaries and wage costs, including fringe benefits ($26,600 average per FTE) and overtime ($7,300 average per FTE). Overtime costs are higher than average for the apprentice positions as they are deployed across the entire NTPC system, often on short notice for unscheduled periods in response to system emergencies. The Hydro Communities' analysis also ignores that apprentice positions will receive greater benefits due to higher than average location differentials due to being based in more remote communities. Consequently, the Hydro Communities recommendation does not fairly reflect the costs of providing four apprentice FTE positions and should be dismissed by the Board." (NTPC Reply, p. 10, *ll*. 10 – 20)

Views of the Board

The Board finds that NTPC has provided a satisfactory explanation for the seemingly high 07/08 forecast cost for the 4 apprentice positions. The Board will not act on the HC recommendation to reduce the forecast 07/08 salaries and wages for these 4 positions.

6.2 Non-Production Fuel

The non-production fuel expenses from the previous GRA to the current GRA forecasts are shown in Table 6.3. The data was obtained from Table 3.3 and Schedules 3.1 and 3.2 revised May 16th.

Table 6.3 – Non-Production Fuel Expenses ($000s)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Hydro	Not Provided	Not Provided	Not Provided	448	69	247	252
Thermal	Not Provided	Not Provided	Not Provided	477	393	484	494
Overall	588	Not Provided	Not Provided	925	461	730	745

NTPC is seeking Board approval for non-production fuel expenses of $0.730 million in 06/07 and $0.745 million in 07/08. The increases ($0.142 million and $0.157 million, respectively) over the 01/03 Settlement reflect the pressures of higher fuel prices.

The interveners did not raise issues with respect to non-production fuel.

Views of the Board

The Board has not identified any issues to warrant deviating from NTPC's forecasts for 06/07 and 07/08. NTPC's forecast non-production fuel expenses for 06/07 and 07/08 are approved by the Board for inclusion in the revenue requirement.

6.3 Supplies and Services

NTPC is seeking Board approval for its supplies and services forecast expenses of $10.889 million for 06/07 and $11.091 million for 07/08.

Table 6.4 summarizes the total supplies and services data provided in Table 3.3 and Schedules 3.1 and 3.2 revised May 16th.

Table 6.4 – Supplies and Services ($000s)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Hydro	Not Provided	Not Provided	Not Provided	Not Provided	Not Provided	5,482	5,581
Thermal	Not Provided	Not Provided	Not Provided	Not Provided	Not Provided	5,266	5,368
Overall	8,587	Not Provided	Not Provided	10,120	9,189	10,748	10,948

The supplies and services expenses include the costs for maintaining the plants and equipment and include such costs as supplies, freight, contractors, professional development and administration. There is a $2.161 million increase from the 01/03 Settlement to the 06/07 forecast. Major components of the increase are:

Insurance and the RFID – The Corporation's cost for external insurance and self-insurance via the Reserve has increased substantially.

Bluefish – The addition of the Bluefish Generating Station has increased supplies and services.

Brushing – NTPC has increased its brushing efforts to reflect a normal annual level of brushing work.

Computer Licensing – This is largely due to new annual licensing costs replacing one-time costs that were previously capitalized.

Satellite and Communication Costs – The Corporation has required increased telecommunication and bandwidth requirements since 02//03.

Outside of these 5 factors, the increase in supplies and services from the 01/03 Settlement to the 06/07 forecast is less than the rate of inflation.

The interveners raised concerns with 2 aspects of the supplies and services expense:

1. Transmission and Distribution Brushing
2. Operational Savings from Bluefish

These two issues are addressed by the Board in the following sections.

NTPC's supplies and services expense forecasts for 06/07 and 07/08 are approved by the Board subject to the Board directions in Sections 6.3.1 and 6.3.2.

6.3.1 Transmission and Distribution Brushing

In recognition that brushing is an essential component of maintaining the reliability of transmission and distribution systems, NTPC proposes to significantly increase its brushing expenses, as compared to 2002/03, to reflect a normalized annual level of brushing work. In TGC.NTPC-38(e), NTPC clarifies that in referring to an annualized level of brushing, NTPC meant that it has attempted to set brushing budgets for each area at a level that is generally representative of the typical average annual level of effort required to address all brushing requirements in a timely fashion.

In BR.NTPC-12, NTPC provided descriptions of its 03/04, 04/05 and 05/06 actual brushing activities and its 06/07 and 07/08 forecast brushing activities. NTPC also provided two tables (BR.NTPC-12(b).1 and 2) that showed its 01/02 and 02/03 forecast costs, its 04/05 and 05/06 actual costs and its 06/07 and 07/08 forecast costs.

The data in BR.NTPC-12 was supplemented with the 01/02, 02/03 and 03/04 actual costs by Undertaking 7. Table 6.5 provides a summary of the brushing expenses.

Table 6.5 – Brushing Expenses

	Transmission	Distribution	Total
2001/02 Forecast	$114,000	$79,000	$193,000
2001/02 Actual	$8,000	$10,000	$18,000
2002/03 Forecast	$116,000	$80,000	$196,000
2002/03 Actual	$33,000	$11,000	$44,000
2003/04 Actual	$17,000	$129,000	$146,000
2004/05 Actual	$207,000	$71,000	$278,000
2005/06 Actual	$130,000	$16,000	$146,000
2006/07 Forecast	$213,000	$180,000	$393,000
2007/08 Forecast	$217,000	$184,000	$401,000

When the HC questioned NTPC regarding its brushing policy, NTPC responded as follows.

> "MR. TERENCE COURTOREILLE: Historically the Corporation would conduct its brushing requirements on an as-and when-needed basis.
>
> Recently, however, the Corporation undertook an internal evaluation of its brushing requirements and the forecast numbers that you see proposed for the test years in this table would represent what we're proposing as our minimum brushing requirements on an annual basis.
>
> MR. TOM MARRIOTT: And can you explain what those are? Is it -- is it quite a complicated series of steps or is it something that you could describe at a high level? Like, I'm looking for perhaps a brushing cycle, something along those lines.
>
> MR. TERENCE COURTOREILLE: It's certainly more defined for the transmission line. For the areas that have road access, we would brush on a rotating annual basis every five (5) to six (6) years. For those areas that do not have road access, we would brush on an annual rotating basis every twelve (12) years.
>
> MR. TOM MARRIOTT: Okay. And is there no set time for distribution?
>
> MR. TERENCE COURTOREILLE: Distribution is not as structured because a lot of our plants have very little sp -- particularly the plant -- the plants in the northern part of the territory, would have very little brushing requirements. So, in regards to those plants, we're still brushing on an as and when-needed basis.
>
> In the southern communities where vegetation growth is much more rapid, we're proposing an annual budget of sixty thousand dollars ($60,000) per year for the Dehcho region and an additional sixty thousand dollars ($60,000) per year for the North Slave Region." (Tr. Vol. I, p, 155, *ll*. 6 – p. 156, *ll*. 15)

The HC summarized the brushing data and provided its views in its argument.

> "… it is noteworthy that NTPC's rates had provided for $115,000 per year for the period 2001/02 through 2005/06, but it only expended $79,000 per year on average or 32% below forecast for transmission. NTPC's rates provided for $80,000 per year for the period 2001/02 through 2005/06 but it only expended $47,400 per year on average or 40% below forecast for

> distribution. It is apparent from the above table that NTPC is catching up in the test years for not maintaining brushing activities over the last 5 years. This has all the attributes of yet another retroactive deferral account.
>
> NTPC advised that it did not have a written brushing policy and historically conducted its brushing "on an as when and needed basis" although it recently undertook an internal evaluation of its brushing requirements to determine its forecast for the test years. While there is no evidence to dispute the test years forecast per se, NTPC should not be compensated twice for the same work. Clearly, NTPC did not maintain its brushing program since the last GRA and is now faced with a serious catch up situation.
>
> NTPC under spent by $185,000 on transmission and by $163,000 on distribution over the last 5 years. Assuming the forecast test year expenditures are now in fact required to bring brushing up to standard, the normalized annual brushing over the 7 year period will have been approximately $92,000 per year for transmission and $86,000 for distribution. On this basis, the Hydro Communities submit that transmission brushing should be reduced by $121,000 and $125,000 in the test years and distribution brushing should be reduced by $94,000 and $98,000 in the test years to ensure that NWTPC is not compensated twice for the same work." (HC Argument, p. 19)

NTPC responded to the HC in its reply.

> "Clearly the forecast brushing expenses for the test years are intended only to reflect normal annualized amounts for brushing requirements and are not in any way to address a "serious catch up situation" for previous years. The appropriate basis for regulatory review is the level of costs forecast to be incurred in the test years, in this case to maintain a standard annual brushing requirement. The only evidence is that NTPC has forecast 2006/07 and 2007/08 brushing costs based on what will normally be required annually over the long-term to maintain an appropriate and safe brushing program. As a result, the Hydro Communities' speculation regarding a "serious catch up situation" is incorrect. The Board should reject the Hydro Communities' recommendation and approve the Corporation's forecast brushing requirements." (NTPC Reply, p. 15, *ll*. 11- 19)

TGC stated in its reply that it was in agreement with the position taken by the HC in its argument.

Views of the Board

The Board is concerned about the large discrepancy from 01/02 to 05/06 between revenue collected by NTPC for brushing and the actual brushing expenditures. The Board calculates this discrepancy to be $345,000.

The HC argues that NTPC under-spent on brushing from 01/02 to 05/06 and that the increased brushing expenditures forecast for 06/07 and 07/08 are a result of NTPC now being in a catch-up situation. The HC assert that NTPC should not now be compensated for work for which it has already been compensated.

NTPC argues that the increase in brushing expense for the test years is not because it is in a catch-up situation. NTPC asserts that its proposed brushing expenditures in 06/07 and 07/08 accurately reflect the necessary level of normalized annual brushing and is not a result of under-spending in 01/02 to 05/06.

The Board finds the characterization of the situation to be beside the point. NTPC has either 1) under-spent $345,000 from 01/02 to 05/06 or 2) over-collected $345,000 in 01/02 to 05/06. Either way, the ratepayers paid $345,000 for brushing services that they did not receive and the Board finds this to be unacceptable.

As there is no evidence to the contrary, the Board accepts NTPC's argument that the forecast expenditures of $393,000 for 06/07 and $401,000 for 07/08 represent the necessary, normalized level of brushing on a go-forward basis.

Accepting NTPC's argument on this point effectively means that NTPC over-collected $345,000 from the ratepayers from 01/02 to 05/06.

The Board directs NTPC, in its Phase 1 refiling, to calculate its total 06/07 and 07/08 supplies and services expenses using its forecast brushing expenditures of $393,000 for 06/07 and $401,000 for 07/08.

The Board directs NTPC, in its Phase 1 refiling, to propose a procedure for returning to the ratepayers over a 3-year period the $345,000 that was over-collected by the Corporation for brushing over the 01/02 to 05/06 period. To be clear, the refunded $345,000 is to be obtained from NTPC's non-regulated cash flow, not by reducing the test year brushing expenditures.

The Board recognizes that there will be year-to-year fluctuations in what is spent on brushing. However, to ensure that such a situation does not occur again and also to capture NTPC's assertion that the normalized brushing expenditure represents the minimum required annually, the Board directs NTPC that, commencing with the 06/07 test year, NTPC's 3-year rolling average actual brushing expenditures must be no less than 10% below the 3-year rolling average forecast brushing expenditures. NTPC's 5-year rolling average actual brushing expenditures must be no less than equal to the 5-year rolling average forecast brushing expenditures.

6.3.2 Bluefish Supplies and Services

NTPC purchased the Bluefish Generating Station in 2002. The benefits expected by NTPC included avoided diesel generation, reduced future diesel engine replacement at the Jackfish Lake plant, and an increased ability to meet future load growth on the Snare-Yellowknife system.

NTPC states that while Bluefish has resulted in significantly reduced overall costs with large savings in diesel fuel use being offset somewhat by increases by the operating and capital costs of Bluefish. In the area of supplies and services, the 06/07 and 07/08 forecasts are $0.277 million and $0.282 million (Table BR.NTPC-9), respectively.

The difference between what was forecast for Bluefish at the time of purchase and the forecast for the 2 test years was explored in BR.NTPC-9. The Project Permit forecast supplies and services for 02/03 and 03/04 as $0.146 million so the 06/07 and 07/08 forecasts represent $0.131 million and $0.136 million increases, respectively. The two primary reasons given by NTPC for these increases are:

1. Initially significant work had to be undertaken in order to meet safety requirements and to improve operational efficiencies. On an on-going basis, more work is required than originally expected to maintain the facility. This also accounts for the increased use of contractors as well.
2. The Bluefish project permit did not specifically identify the impact of Bluefish on the Corporation’s insurance costs. For the purposes of budgeting in 06/07 and 07/08, Bluefish has been allocated $96,000 of NTPC’s insurance costs.

In HC.NTPC-13(l), the HC requested the supplies and services expenses for Jackfish, Bluefish and Snare for 02/03 through 07/08. NTPC provided the following summary:

	2004/05 Actual	**2005/06 Actual**	**2006/07 Forecast**	**2007/08 Forecast**
Jackfish	1,882	1,722	2,189	2,225
Snare	497	532	746	761
Bluefish	65	280	254	259
Totals	2,445	2534	3,189	3,244

Note: The costs for General & Administration are not tracked separately between Bluefish, Jackfish and Snare, therefore they are all included with costs for Jackfish

It appears to the Board that the 06/07 and 07/08 forecasts for Bluefish in the above table are in error and should be approximately $0.277 million and $0.282 million, respectively, to be consistent with Table BR.NTPC-9. These corrected figures would also be consistent with the 05/06 actual expense of $0.280 million. However, NTPC's response to NUL.NTPC-15(b) further confuses the issue.

The HC pursued this line of questioning at the hearing and again in their argument. The basic thrust of the HC position is that the purchase of the Bluefish Generating Station should have provided reductions in supplies and services at Jackfish due to the reduced need for diesel generation. When questioned by the HC, NTPC responded that there were three primary reasons why the Jackfish supplies and services expenses have increased despite the decreased generation:

1) General and administration expenses for Snare, Bluefish and Jackfish are all included in the Jackfish supplies and services;
2) The change to the RFID required a budget be established for events between the old threshold of $5000 and the new threshold of $100,000; and
3) Increases to computer licensing costs.

The HC's evaluation of this information was summarized in its argument:

> "HC.NTPC-13(l) provided a breakdown of supplies and services for each the Jackfish, Snare and Bluefish generating facilities. Again, rather than a decrease in operating expenses, supplies and services are forecast to increase. It appears that the Jackfish supplies and services include far more than just the supplies and services required for the operation of Jackfish (i.e. collection of bad debts, long service awards, termination costs, general and administration for the entire Snare/Yellowknife system, administration for the region). Again, it is impossible to determine from HC.NTPC-13(l) whether there have been any savings in supplies and services as a result of the Bluefish purchase." (HC Argument, p. 16 – 17)

Given that the information provided by NTPC did not permit a clear calculation of salaries and wages reductions at Jackfish due to Bluefish, the HC recommendation to the Board is:

> "…The Hydro Communities submit absent any demonstrated savings in operating expenses as a result of the Bluefish purchase, the Board should maintain Jackfish salaries and supplies and services at the 2005/06 levels shown in … HC.NTPC-13(l)." (HC Argument, p. 17)

The NTPC countered in its reply:

> "It is clear that at the time of the project permit application, the feasibility of the project did not hinge on achieving any non-diesel fuel operating expense savings. Rather, the project was and continues to be justified on basis of avoided diesel fuel and engine replacement costs. This is clearly demonstrated in the attachment to BR.NTPC-29(k), which indicates that the only variable (meaning O&M, Salaries and Wages, and Supplies and Services) savings from Bluefish included in the project permit application economics was based on 2.5 cents per diesel kW.h displaced. This savings reflects the costs of overhauls and other related savings, such as oil changes at the Jackfish units, which would have otherwise been part of NTPC's revenue requirement over time. In short, in contrast to Hydro Communities' assertions, the purchase of Bluefish was not predicated on saving in Salaries and Wages and Supplies and Services at Jackfish. Despite this, Ms. Goucher noted that the purchase of Bluefish, in

> combination with changes to the industrial loads on the Snare-Yellowknife system, has allowed NTPC to reduce Jackfish plant operators by five positions, a benefit in excess of those assumed at the time of the Bluefish purchase." (NTPC Reply, p. 11, *ll*. 8 – 20)

Views of the Board

The Board agrees with NTPC that the Bluefish purchase was not predicated upon, and might not result in, demonstrated operational savings in supplies and services at Jackfish. While such savings can and should be sought by NTPC whenever feasible, the Board is satisfied that the supplies and services forecasts provided by NTPC do not require an adjustment by the Board. The Board will not act upon the recommendation from the HC to maintain the Jackfish supplies and services at 05/06 levels.

The Board directs NTPC to reconcile the 06/07 and 07/08 Bluefish supplies and services forecasts shown in Tables BR.NTPC-9 and HC.NTPC-13(l) and described in NUL.NTPC-15(b). NTPC is to adjust the Bluefish supplies and services forecasts as needed to account for any errors in their information request responses.

6.4 Travel and Accommodation

NTPC's travel and accommodation expense includes all the travel, accommodation and meal costs associated with staff travel for operational and professional development purposes.

Table 6.6 summarizes the travel and accommodation data provided in Table 3.3, Schedules 3.1 and 3.2 revised May 16th and Undertaking 8.

Table 6.6 – Travel and Accommodation ($000s)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Hydro	Not Provided	Not Provided	Not Provided	685	714	851	876
Thermal	Not Provided	Not Provided	Not Provided	1,020	1,107	1,284	1,323
Overall	1,939	1,594	Not Provided	1,705	1,821	2,135	2,199

NTPC's forecast for 06/07 is $2.135 million, which represents an increase of $0.196 million from the 01/03 Settlement. That increase represents about an average annual increase of 2.4%, which is approximately equal to overall inflation. The 07/08 forecast of $2.199 million is a further increase of $0.064 million (3%) over the 06/07 forecast.

Both the TGC and the HC requested that the travel and accommodation expense be broken out into operations versus professional development and training (TGC.NTPC-39(c), HC.NTPC-13(o) and Undertaking #8). This is shown in Table 6.7.

Table 6.7 – Travel and Accommodation Separated into Accounts ($000s)

	01/02 Actual	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Operations	1,735	Not Provided	1,497	Not Provided	1,552	1,774	1,786	1,840
PD and Training	103	Not Provided	97	Not Provided	154	87	349	359
Total	1,838	1,939	1,594	Not Provided	1,706	1,861	2,135	2,199

The Board notes that there is a discrepancy of $40,000 in the 05/06 actual provided by Schedules 3.1 and 3.2 as compared to TGC.NTPC-39(c).

The Board also requested a break-down of the travel and accommodation expenses but according to Head Office versus Plants. NTPC provided the following data in its reply to BR.NTPC-13. This is shown in Table 6.8.

Table 6.8 – Travel and Accommodation – Head Office vs. Plants ($000s)

	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Plants	1,411	1,474	1,665	1,715
Head Office	294	347	470	484
Total	1,705	1,821	2,135	2,199

The 06/07 and 07/08 forecasts for Plants and Head Office are broken out further in SM-5 and Tables NTPC.TWU-13(a) and (b) according to Hydro vs. Thermal and also into the individual plants.

An additional breakdown of the travel and accommodation expense into its components is provided in Table BR.NTPC-8.

NTPC justified the increases from 04/05 to 06/07 in its reply to BR.NTPC-8.

> "Increases from 2004/05 to 2005/06 reflect overall higher travel costs as well as the full year impact of the addition of Bluefish to the system. From 2005/06 to 2006/07 increases reflect two factors outside of inflation: First, additional amounts are included to address additional costs that will arise in O&M expenses as a result of the changes to the RFID policy, as noted above. An additional factor in the increase is related to increased training requirements discussed above under Administration."

The increase in the travel budget in the test years due to the change in the RFID is $100,000/year. NTPC does not quantify the increase in travel due to the increased training requirements.

The TGC questioned NTPC about the controls that are in place to minimize these expenses. NTPC provided the following response to TGC.NTPC-39(b):

> "In order to ensure that travel and accommodation costs are properly contained the Corporation has a number of controls in place. The first control is during the budget process where travel expenses are reviewed by Senior Management against historical travel and in consideration of

> other lower cost options (e.g. video conference, conference call, telephone interviews). Employees are encouraged to combine travel for different purposes where possible (e.g. community meetings, plant visits, medical travel, etc.). Supervisory approvals are required for all travel and additional approval is required for certain types of travel (e.g. Human Resources approves medical travel, Senior Management approves travel outside of NWT). Travel claims are reviewed and signed by Supervisors to ensure that low cost travel options are selected (e.g. economy airfares, direct routing, government rates for accommodation and rental vehicles) and that costs are supported by receipts. Travel expenses are subject to regular review by the Internal and External Auditors."

In its argument, the HC provided its analysis and recommendation to the Board.

> "The travel and accommodation related to operations appears reasonable to the Hydro Communities. Although NPC identified environmental training (including fuel handling) and safety training (under emerging WCB regulations), it is still difficult to fathom close to a 200% increase in professional development travel and accommodation over the $113,000 average of actual costs in the three prior years shown in the table above. Under the circumstances, the Hydro Communities submit that no more than a doubling of the $113,000 average professional development costs should be allowed, that is $226,000 per test year." (HC Argument, p. 20)

NTPC countered this recommendation in its reply.

> "The Hydro Communities' comment, however, fails to acknowledge the difficulty in tracking professional development travel costs versus operational travel costs as the Corporation will often schedule operational meetings and professional development events for the same trip, thus minimizing overall travel costs. Consequently, the Corporation's travel and accommodation forecasts should be evaluated having regard to the total budgeted expense, as opposed to individual components. In total, despite major increases in industry travel costs since 2001/03, including fuel surcharges, and the fact that apprentice positions require more travel and accommodation expenses because they are used system wide, the Corporation has kept the growth in travel and accommodation budgets to approximately 2.4% per year – well within the level of simple inflation. As a result, the Corporation submits that there is sufficient evidence on the record for the Board to be satisfied that the travel and accommodation

> forecasts in the test years are reasonable and therefore should be approved." (NTPC Reply, 15, *ll*. 31 – p. 16, *ll*. 7)

The TGC stated in its reply that it agreed with the recommendation of the HC.

Views of the Board

The Board finds NTPC's referral to a 2.4% annual average increase since 02/03 to be unhelpful given that this figure is calculated based upon the 01/03 Settlement, not the 02/03 actual. Using the 02/03 actual as the base year figure, the Board calculates that the actual annual average increase in the travel and accommodation expense is 7.6%, which the Board finds to be excessive. However, the Board recognizes that the 06/07 forecast also includes two new cost drivers that were not present in earlier years: the change in the RFID and increased training due to regulatory requirements.

While NTPC has quantified the impact of the change in the RFID as $100,000/year, it has unfortunately not quantified the impact of the increased regulatory training, which is cited as the other major cost driver.

Assuming a range of $50,000 to $100,000/year for the increased regulatory training and using the $100,000/year identified by NTPC for the change in the RFID, the Board calculates the annual average increase absent these 2 cost drivers to be in the range of 5.0% to 5.6%, which, while still high, is reasonable over that time period.

The Board approves NTPC's 06/07 and 07/08 forecast travel and accommodation expenses.

7. AMORTIZATION

7.1 Fixed Assets Amortization

NTPC requested approval of amortization expenses (net of customer contributions) of $9.568 million and $10.115 million in 2006/07 and 2007/08 respectively for fixed assets.

NTPC used the same rates as accepted in the 01/03 Settlement. However, NTPC indicated the amortization true up from the negotiated settlement has ended.

NTPC explained why it did not complete a depreciation study for the test years:

> "NTPC began but did not complete a depreciation study. NTPC did full depreciation studies for the last two GRA's which provided detailed reviews of asset lives and site restoration costs. Utilities do not normally do full depreciations studies for every GRA.
>
> The current GRA requires a large increase to deal with fuel price increases, loss of credits, investment, regulation and inflation. The preliminary work on the depreciation study was indicating the need for additional increases due to depreciation and NTPC did not want to apply for any potential increases at the same time as the other increases and not without a more thorough review of the study results and more information on how Asset Retirement Obligations (ARO) recommendations of the Canadian Institute of Chartered Accountants (CICA) will impact depreciation rates, true ups, equity and the Revenue Requirement.
>
> The various methods of dealing with the new ARO's have the potential to have a material impact on NTPC's GRA and depreciation rates depending on whether the recommendations of the CICA are followed or ignored for rate making purposes or whether the Board approves NTPC's proposal in

> the GRA or whether the Board approves another approach to for dealing with ARO's.
>
> Once the question of how ARO's will be handled NTPC will complete a new depreciation study reflecting newer historical information, updated site restoration information and the approved ARO treatment." (NTPC Argument, p. 21, *ll*. 3 - 22)

Views of the Board

The Board notes there could be differences between regulatory requirements and reporting requirements. The procedures and rules concerning depreciation accounting for regulatory purposes are long established. Therefore, in the Board's view any new CICA reporting requirements need not deter NTPC from completing a depreciation study based on established procedures and rules in a timely fashion.

The Board accepts NTPC's proposed amortization of fixed assets subject to the comments in Section 7.2 of this Decision.

7.2 Reserve for Future Removal and Site Restoration

The amount included in the accumulated amortization with respect to future removal and site restoration is set out in BR.NTPC-16 for each asset category.

In response to a Board directive in Decision 1-2002 to provide an updated estimate of soil remediation costs, including an estimate of the costs that are considered recoverable from the Federal Government, NTPC indicated it has completed an updated soil remediation assessment, based on estimated volumes of impacted soil and unit costing of remediation for similar projects carried out in northern Canada. NTPC stated the estimated soil remediation cost was $12.959 million in 2005 based on a study conducted by Biogenie in January 2006. A copy of the study was provided in Exhibit 4 and Undertaking #6.

NTPC submitted in regards to estimates of the costs considered to be recoverable from the Federal Government, NTPC has pursued Canada in regards to the commitments of the Acquisition Agreement. However NTPC indicated the Corporation has not been successful with those discussions.

The Corporation submitted it does not expect any recoveries and may risk undermining the discussions/negotiations by providing speculation at this point in time. Any recoveries that NTPC secures will be credited against the Net Salvage Reserve, and will ultimately go to lower the amounts ratepayer would otherwise pay to that reserve for site restoration. (Ex. 2, p. 6-2, 6-3)

NTPC indicated the recording of future removal of assets and site clean up costs was supported by Generally Accepted Accounting Principles ("**GAAP**"), and approved by the Board as part of the Corporation's periodic depreciation reviews. Changes to GAAP in the last few years now require the recording of a liability only in cases where there is a "legal obligation" for the asset disposal or site clean up and to reverse to equity any other retirement obligations liabilities.

NTPC submitted to ensure fair intergenerational allocation of costs (that customers are paying for the cost of the assets they are using, including costs of disposing these assets and restoring the facility sites) as well as smoother rates, NTPC would like to continue with its past practice of maintaining a liability (the Reserve for Future Removal and Site Restoration) for the removal and clean up of all its assets regardless of legal obligations or otherwise. (Ex. 2, p. 3-12, 3-13)

The HC submitted the Corporation was directed to provide an updated estimate of soil remediation costs including an estimate of the costs that are considered recoverable from the Federal Government, at the time of its next GRA. NTPC filed an updated soil remediation estimate of $12.959 million in 2005 dollars. NTPC has included an annual appropriation of $600,000 per year for Future Removal and Soil Remediation. The study indicated that approximately 90% of the costs related to the period when Northern Canada Power Corporation ("**NCPC**") was owned by the Federal Government.

The HC submitted they expect the Corporation to continue to monitor and pursue funding from the Federal Government for the soil remediation that they are responsible for. (HC Argument, p. 23)

In its reply submission, the Corporation undertook to continue to monitor the situation and pursue the Federal Government further should there be new developments or programs. NTPC submitted the Corporation's efforts with respect to recovering funding from the federal government have been prudent and reasonable to date. NTPC stated the Board and Hydro Communities can take comfort from the Corporation's commitment for future monitoring of the issue. (NTPC Reply, p. 21)

The adequacy of the current balance to deal with these anticipated future costs is at the present time uncertain. This is part of the assessment underway over the next number of years with respect to NTPC's current depreciation rates, reserve for future removal balances and treatment of Asset Retirement Obligations as they relate to regulatory accounting and rate setting.

Views of the Board

The Board notes the accumulated site restoration component included in accumulated amortization is as follows:

	2004/05	2005/06	2006/07	2007/08
	$000	$000	$000	$000
Accumulated reserve for site restoration	37154	37780	38853	39967

Source: BR NTPC 16 Table 1

The Board considers that although there might be other costs related to site restoration in addition to soil decontamination, there appears to be a very large difference between the accumulated reserve for site restoration as of fiscal year end 2004/05 of $37.154 million and the estimated cost of soil decontamination, in the sum of $12.959 million in 2005 dollars, as per the Biogenie study. The Board notes NTPC's evidence at the time of the 2001/02 and 2002/03 GRA that the estimate of negative salvage for diesel plant site restoration, excluding soil remediation costs, was in the vicinity of $12.9 million. (Decision 1-2002; p. 6)

The Board notes NTPC's view that the adequacy of the current balance in the accumulated reserve to deal with anticipated future costs is at the present time uncertain. However, the Board is concerned by the significant and growing gap between the potential amount required for site restoration including soil remediation as reflected in the Biogenie study and as per the evidence referred to in Decision 1-2002, and the accumulated balance in the reserve for site restoration. The Board notes from the above table $1.073 million in 2006/07 and $1.114 million in 2007/08 will be added to the reserve for site restoration, thereby contributing to the gap between the potential amount required for site restoration and the accumulated balance in the reserve for site restoration. The Board notes the Corporation has not had an opportunity to respond to this perspective on the accumulated balance in the reserve for site restoration. The Board, therefore, directs NTPC to provide, as part of the refiling, an assessment of the significant and growing gap between the accumulated balance in the reserve for site restoration and the estimated site restoration costs in light of the above discussion and propose a cap to the accumulated reserve balance until such time as studies on the adequacy of the current balance can be completed. In this regard, the Board estimates if the accumulated reserve is capped at the 2005/06 year end level, amortization expense would be reduced by $1.073 in 2006/07 and $1.114 million in 2007/08.

NTPC is directed to complete the assessment of the adequacy of the current balance in the accumulated reserve to deal with NTPC's share of anticipated future costs for site restoration including soil remediation and reflect this assessment in the amortization rates at the time of the next GRA.

The Board accepts NTPC's request to maintain the reserve (the Reserve for Future Removal and Site Restoration) for the removal and clean up of all its assets regardless of legal obligations or otherwise until an assessment of the adequacy of the current balance in the accumulated reserve to deal with NTPC's share of anticipated future costs for site restoration including soil remediation is completed.

7.3 Amortization of Deferred Charges

NTPC set out details of each of the deferral account amortizations in BR.NTPC-21.

7.3.1 Overhaul Deferral Account

The Corporation requested permission to set the annual appropriation for overhauls at $1.693 million. A continuity schedule of the overhaul deferral account since March 31, 2004 was provided in BR.NTPC-21.

Views of the Board

The Board accepts the overhaul deferral account forecast as proposed.

7.3.2 Water Licensing Fee Deferral Account

Due to increasing uncertainty related to the costs and terms of water licenses, NTPC proposed to establish a new deferral account for water licensing fee. A continuity schedule of the water licensing fee deferral account is provided in HC.NTPC-15 Table 3.

The HC did not object to the establishment of a water licensing fee commencing in 2006/07. However, the HC submitted that NTPC should not be able to recover through the deferral account any deferred water license fees from prior years when the water license fee deferral was not in existence:

> "…The costs that NTPC incurred for water licensing fees between rate cases are no different than any other unplanned maintenance expenses or any other unbudgeted expense. This is the very reason that utilities receive a risk premium. Utilities should not be allowed to add to their earnings without scrutiny and then apply for retroactive recovery of such expenses. There is no evidence before the Board to demonstrate that such unplanned expense would have been allowed in the years when the expenses regarding water license fees were incurred. For that matter, NTPC admits that $0.04 million was included in the 2002/03 revenue requirement. The Hydro Communities submit that the Board should

> specifically deny the $611,000 (sic) of retroactive expenses related to water license fees incurred prior to the two test years as a matter of principle…" (HC Argument, p. 58)

NTPC submitted deferral and amortization of water licensing fees has been accepted in the past. (NTPC Reply, p. 18) What is being proposed in this application is an approach designed to address the increasing uncertainty over the cost and term of a license. Accordingly, NTPC proposed to amortize the forecast water license fees to 2021/2022 of $1.551 million and an opening unamortized balance of $0.634 million over 16 years. (HC.NTPC-15)

Views of the Board

Noting that the deferral account treatment of water license fees is designed to address uncertainty over the cost and term of each license and since amortization of water license fees has been accepted in the past, the Board accepts NTPC's proposed deferral account treatment for water license fees.

7.3.3 Job Evaluation

NTPC incurred $256,000 in 2003/2004 and 2004/05 in order to carry out a job evaluation study following incorporation of the Equal Pay for Equal Value legislation into the public service act. NTPC proposed to treat the cost of this study as a deferred cost and amortize it over a period of 5 years for the reason the expenditure has enduring benefits beyond the year of expenditure.

The HC took exception to the proposed inclusion of the annual amortization portion of the job evaluation costs in the amount of $61,000, in the test year revenue requirements since NTPC did not have prior Board approval to treat these costs as a deferral account. The HC submitted it is just like any other unbudgeted expense between rate cases and this is the very reason that utilities receive a risk premium. (HC Argument, p. 55)

NTPC stated the Job Evaluation System is properly treated as a deferred cost since it meets the accounting definition of an asset; i.e., it provides long-term or enduring benefits (the previous study related to job evaluation was in 89/90). The deferred cost is amortized over a five-year period. (BR.NTPC-16(c))

Views of the Board

Given the significance of the amount, its enduring benefits beyond a single year and noting the expenditure was the result of a legislative requirement, the Board considers the capitalization and amortization of the job evaluation study expenditure over a period is appropriate. The Board therefore accepts NTPC's proposed deferral account treatment of the job evaluation study expenditure.

In order to address the concerns of HC that the ability to defer certain expenditures should not result in changing the risk assumptions made at the time the fair return on rate base was established, the Board directs NTPC to file a written policy with regard to the criteria that are to be used to determine the eligibility of expenditures for deferral account treatment, at the time of the refiling.

8. DEFERRAL ACCOUNTS

8.1 Reserve for Injuries and Damages ("RFID")

In response to a Board Directive from Decision 1-2002, NTPC filed a proposed policy with respect to the charges to the RFID. NTPC also requested to increase the annual appropriation to the RFID from $485,000 per year to $670,000 per year.

The HC submitted the proposed policy still leaves events that are uninsured or uninsurable to the discretion of NTPC. The HC submitted that these higher impact uninsurable or uninsured events must meet a higher test or degree of scrutiny. The HC also submitted that the only practical solution appears to be to defer disposition of these higher impact events until the next GRA and, if considered appropriate, appoint a qualified independent individual to determine whether the event truly meets the test of "accidental." (HC Argument, p. 57)

NTPC stated that the charges to the RFID are reviewed in detail at each GRA, and as such the Board currently retains full jurisdiction to review all reserve charges as it sees fit. The Hydro Communities' recommendation to have each and every charge reviewed by a third party, and defer confirmation of the charges until such review has occurred, is unreasonable, unnecessary and cannot practically be implemented. (NTPC Reply, p. 20)

Views of the Board

The Board considers all charges to the reserve will be subject to review by the Board and interveners at the next GRA. The Board expects the Corporation to maintain the necessary records to facilitate full scrutiny of the costs and details of the circumstances relating to each accidental event giving rise to a claim against the reserve.

Having reviewed the proposed policy and the continuity schedule of the RFID account, the Board approves the RFID policy as filed and the increase in the annual appropriations from $485,000 per year to $670,000 per year.

8.2 Employee Future Benefits

The employee future benefits deferral account was established in the context of the 01/03 Settlement. The settlement contemplates actual employee termination payments would be charged to this account on a pay as you go basis.

Table 6.7.of the Application shows the changes in this account since March 31, 2001:

	$000
Credit balance as at March 31,. 2001	889
2001/02 Expense	-274
2002/03 Expense	-205
2003/04 Expense	-106
2003/04 Adjustment	250
2004/05 Expense	-44
2005/06 Expense (Forecast)	-353
Credit balance as at March 31, 2006	157
Transfer in ultimate removal portion	495
Revised balance as at March 31, 2006	652
2006/07 Expense (Forecast)	-165
2007/08 Expense (Forecast)	-88
Credit balance as at March 31, 2008	399

With respect to the $250,000 adjustment shown above, NTPC stated this relates to amounts that had been previously recognized in other accounts which fit the appropriate definition of this account. These amounts were therefore consolidated into this account.

With respect to the $495,000 transfer, NTPC stated the amount was included in NTPC's 2001/03 revenue requirement. This amount has since been appropriated from net income.

The TGC indicated it has reviewed the above adjustments and concurs with the NTPC proposals. (TGC Argument, p. 33)

Views of the Board

The Board accepts the NTPC proposed balances for employee future benefits deferral account for inclusion as a component of no cost capital.

9. SALES AND REVENUE FORECAST

The sales forecast by customer class is provided in Schedule 2.1 of NTPC's application. Appendix A to the application shows the sales forecast by customer class by community.

9.1 Industrial Sales Forecast

The HC recommended the Giant mine sales included under the industrial sales forecast in Yellowknife should be increased considering the recorded sales in the last two quarters of 2006/07:

> "…However, the preliminary actual Giant Mine sales for 2006/07 were 4,988 MWh as compared to the forecast of 4,113 MWh for 2006/07 and 3,781 MWh for 2007/08. Although NTPC had forecast the Giant Mine care and maintenance sales to level out at about 315 MWh per month for the last two quarters of 2006/07, that forecast proved to be pessimistic and instead averaged about 416 MWh and there is no discernible downward trend to 315 MWh per month. The average for 2006/07 also was 416 MWh per month. The Hydro Communities submit that, based on the best available information up to the time of the application and to the time of the hearing, it appears that 4,988 MWh for each of test years 2006/07 and 2007/08 would be a reasonable forecast for the Giant Mine care and maintenance sales. The forecast energy and billing demand units should both be increased for purposes of determining revenues." (HC Argument, p. 8)

NTPC submitted the higher sales recorded in the last two quarters of 2006/07 reflects a one-time experience related to high water levels in winter that were not expected by NTPC or the mines. (NTPC Reply, p. 7)

Views of the Board

The Board considers it appropriate to review recorded sales in order to test the forecast assumptions used; however, the Board does not consider it appropriate to substitute actual results for forecasts on a selective basis. With regard to the forecast assumptions, the Board notes NTPC's view the higher recorded sales in the last two quarters of 2006/07 is a one time event and might not be repeated. The Board concludes therefore that the forecast assumptions used by NTPC in regard to sales to the Giant mine are appropriate.

The Board accepts NTPC's industrial sales forecast as proposed.

9.2 Retail Sales Forecast

The Corporation's load forecasting approach is a balance of two broad methods:

- **“"Top-down"** assessment of the activities and plans underway in a community, such as statistics from the GNWT capital spending plans, NWT Housing Corporation plans, and known developments occurring in a community such as construction activity and forecasts provided by other third parties (e.g. NUL, mines, etc). The Corporation's loads are also reviewed by its Operations and field personnel.
- **"Bottom-up"** analysis of loads experienced over the previous period up to 10 years, including two regression methods - one that is simply based on 10 year load patterns (called the "trend" analysis), and one that is based on weather-normalized loads. The regression is not a simple calculation, but rather a methodology that provides outputs of monthly loads.” (BR.NTPC-4, p. 20 of 23)

Fort Smith

For Fort Smith, NTPC indicated it had used the top down approach to arrive at the sales forecasts.

HC expressed concern the forecast of sales for the community of Fort Smith were understated when compared with the normalized actual sales in prior years:

> “Based on the various pieces of information provided, the Hydro Communities have compiled the following summaries of actual and forecast sales per customer (BR.NTPC-4 and Schedule A.8) and HDD (Exhibit 34) for Fort Smith since 2001/02:

	Residential	General Service	HDD	
2001/02A	10660	53660	7120	
2002/03A	10640	52300	7733	
2003/04A	10310	51280	7058	
2004/05A	10470	55390	7726	
4 Year Ave	10520	53140	7409	
2005/06A	9690	53330	6294	
2006/07F	9370	52410	7439	(30 Year Normal)
2007/08F	9270	53120	7439	(30 Year Normal)

> It is obvious from the above that 2005/06 was an extremely mild year in terms of HDD (15% less HDD than the 30 year average) and that the average sales per customer were also well below the preceding 4 year average (residential sales 8% below 4 year average). The HDD in those 4 years were close to the 30-year average. To use this year as the base upon which to add 1% defies logic...” (HC Argument, p. 10)

The HC submitted that the use of the four year average sales per residential and general service customer times the forecast number of customers should be used for the 2006/07 and 2007/08 sales forecasts. HC recommended residential sales per customer should be increased to 10,520 kWh per forecast customer for each test year and general service sales should be increased to 53,140 kWh per forecast customer. (HC Argument, p. 10 – 11)

NTPC explained sales per customer in Fort Smith may be declining for reasons other than heating degree days. NTPC considered conservation may be a factor in the decline:

> "…Sales are indicated by the Hydro Communities to be low in 2005/06 consistent with the warm winter. However, other clearly material factors are impacting the residential sales forecast. For example, 2005/06 sales per customer (at 9.69 MW.h) were below 2003/04 levels (at 10.310 MW.h) by 6.40% at a time when the heating degree days ("HDD") were down by 12.14% (from 7058 to 6294). The correlation, however, does not hold in other cases, such as 2002/03 compared to 2001/02 which indicates a year with HDD 8.6% lower (7120 versus 7733) but results in sales per customer that are 0.2% higher (10.660 MW.h versus 10.640 MW.h). In short, the Hydro Communities' simplified analysis with respect to HDD does not bear out.
>
> In contrast the evidence in this proceeding with respect to Fort Smith is that sales continue to materially decline, whether due to conservation efforts or population declines, such that July 2006 was the second lowest month of sales in Fort Smith for the last ten years. The HC Argument appears to try to dismiss this fact by indicating that it is clearly not related to HDDs. In this respect, the Hydro Communities are correct because HDDs will not affect loads in July, however, it also serves to clearly illustrate how many other factors are driving loads in this community and the degree of downward rate driver that this combination represents – a fact that is dismissed out-of-hand by the Hydro Communities. (NTPC Reply, p. 8, *ll*. 9 - 35)

Fort Resolution, Behchoko and Dettah

Fort Resolution, Behchoko and Dettah are communities where NTPC indicated it had used the top down approach to arrive at the sales forecasts.

The HC submitted that the same rationale as for Fort Smith should be applied to sales in Fort Resolution. Sales per residential customer would increase from 6,580 and 6,510 kWh per customer to 6,720 kWh per customer. The HC submitted the 4-year average for Fort Resolution general service customers is only marginally higher than the NTPC forecast and thus no change appears necessary for the general service class. (HC Argument, p. 11)

HC expressed concern that as with the Fort Smith and Fort Resolution Sales Forecasts, 2005/06 residential sales for Behchoko and Dettah appear to be down due to the extremely mild year in terms of HDD and that the average sales were also well below the preceding 4 year average (4.3% and 2.1% respectively for Behchoko and Dettah).

In light of these observations, the Hydro Communities submitted that four year average sales per residential customer times the forecast number of customers should be used for the 2006/07 and 2007/08 sales forecasts. HC submitted Residential sales per customer should be increased to 7,135 kWh per forecast residential customer in Behchoko for each test year and to 8,045 kWh per forecast residential customer in Dettah for each test year. The HC noted the general services sales forecasts do not appear to be unreasonable. (HC Argument, p. 14)

NTPC submitted there is a fundamental flaw in the Hydro Communities' overall analysis, which overextends the type of HDD correlation that might exist on a larger and more diverse load population as compared to the extremely small centers. (NTPC Reply, p. 9)

Thermal Communities

TGC noted since NTPC uses normalized sales for only a few thermal communities and considering the difficulties involved in preparing accurate sales forecasts for these communities, the Board should adjust up the sales forecasts for thermal communities by 1.17% being the percent by which actual sales for thermal communities exceed the forecast in 2006/07. (TGC Argument, p. 37)

The TGC submitted the average use per customer should provide the Board with a useful tool to assess the reasonableness of the total forecast sales. The TGC noted a consistent overall downward bias in the 2007/08 sales per customer in most of the thermal communities. TGC submitted a 1.17% upward adjustment to sales in 2007/08 should cater for whatever bias is built into the 2007/08 sales/load forecast arising from a downward trend in the sales/customers observed in most of the thermal communities. The TGC submitted the Board should direct NTPC to provide, at its next General Rate Application, a comprehensive assessment of the annual changes in the sales per customer and address whether NTPC should employ average, as opposed to year-end number of customers. (TGC Argument, p. 38 – 39)

NTPC submitted that simply because preliminary actuals are now available (and TGC appears to prefer those results), there is no reason for the Board to reject NTPC's reasonable GRA forecasts.

NTPC submitted the 1.17% adjustment bears no linkage whatsoever to 2007/08 forecasts, as it is not based on any values arising from that year, and as such the TGC recommendation with respect to 2007/08 should be dismissed by the Board. (NTPC Reply, p. 5)

NTPC submitted, while sales per customer multiplied by total number of customers may be the methodology utilized by some utilities, it is not utilized by NTPC. Rather, the Corporation's sales forecast is done in aggregate for each customer class and community solely based on the total sales in kWh. (NTPC Reply, p. 6)

Views of the Board

The Board notes that, due to certain data limitations, regression analysis for both trend and weather normalized conditions are not always used. Instead alternative methods of forecasting based on averages of consumption from the same month in previous years or averages of the most recent month's consumption are used.

> "…In each case, the regression analyses for both trend and weather-normalized conditions are run, and the fit assessed for reasonableness. However, data limitations are often encountered due to the small size of the communities (for example, in certain billing cycles, no consumption will be recorded for a given month and double consumption the following month, due to meter read cycles varying for example from on the order of 28 days to 35 days for practical reasons - if only a few customers are out of cycle, this can materially affect the usefulness of the monthly data for regression-type analysis). As a result, NTPC also considers other alternative methodologies, such as:
>
> - straight-line growth
> - averages of consumption from the same month in previous years
> - averages of the most recent month's consumption.
>
> Each of these methodologies will be used in certain cases in order to ensure the "bottom-up" analysis results in loads that are consistent with the "top-down" assessment by the field personnel familiar with the communities." (BR.NTPC-4, p. 21 of 23)

The Board notes NTPC's difficulty in forecasting monthly sales given the small size of several communities and the concern that if a few customers are out of cycle, this can materially affect the usefulness of the monthly data for regression-type analysis. The Board considers that while these might be concerns, they are nevertheless not insurmountable.

The Board considers that while the bottom up and top down approaches described above are consistent with prudent forecasting practice, the Board is concerned by the lack of complete explanations or support for the load forecast assumptions used for certain communities as reflected in Table BR.NTPC-4(d). The Board notes NTPC's analytical methods do not consider normalized average use per customer. The Board considers normalized average use per customer to be a useful forecasting tool, among others, because it takes into consideration the impact of changes in customer numbers on the sales forecast. It can also provide indications of trend in customer usage and usage patterns.

The illustration provided by HC in relation to Fort Smith is an example of how a four-year average of average use per customer may be used to test the forecast sales. The use of historical averages could be useful particularly if a single year use per customer might not be accurate as a result of out of cycle metering issues. The Board also notes TGC's views on the use of average use per customer in forecasting sales in future proceedings.

The Board considers NTPC should consider historical normalized average use per customer, among other methods, in determining its sales forecast for residential and general service customers by community. The historical normalized average annual use should be averaged over the most recent four years if there are out of cycle metering issues. The Board directs NTPC, as part of its Phase 1 refiling, to adjust the Test Year sales forecasts by community having regard to historical normalized average use per customer and any other relevant factors considered in the top down and bottom up approaches. The Board also directs NTPC to reflect any consequential impacts of any changes in sales forecasts on fuel costs and any other second order impacts, in the refiling.

The Board directs NTPC to consider among other forecasting techniques normalized average use per customer, for purposes of future GRA filings.

9.3 Revenue Uncertainty Due to Material Load Additions

The Hydro Communities submitted that there is sufficient uncertainty surrounding the potential increases and treatment of incremental revenues to NTPC prior to the next GRA from new mining loads or the diamond mines and through corporate restructuring such that a deferral account to capture these incremental revenues and any related costs is warranted. The HC submitted the potential for these incremental revenues should be considered not just over the term of the Test Years in this Application but over the next 5 years, which is the interval since NTPC's last GRA. (HC Argument, p. 6)

HC also submitted that Northland Utilities (NWT) Limited should continue to be supplied by hydro power from the existing Taltson Hydro Plant facilities in preference to new customers to be served by the proposed non-regulated NTHC. HC submitted this may require the negotiation of a new wholesale power supply if that situation arises. (HC Argument, p. 7)

In reply, NTPC submitted the timing of any new mining load is simply not known at this time and certainly beyond the Test Years. Further, NTPC stated the Corporation requires a rate schedule to be approved by the Board for new mining load. In the event that NUL were to serve a new mine load, the Corporation would be back before the Board on its own accord or at the direction of the Board if NTPC's incremental wholesale revenues were material and changed its level of earnings to the extent that its rates were no longer appropriate. (NTPC Reply, p. 4)

Views of the Board

The Board recognizes the potential for significant changes in the costs and revenues of the Corporation if significant new loads were to develop. The Board therefore considers a mechanism is required to review and assess the impact of these changes in the Corporations rates. Accordingly, the Board directs NTPC to provide to the Board and to all interested parties a report on the costs and revenues associated with new industrial, mining or wholesale loads, or load increases, that would have a material impact on its level of earnings and/or rates. This information should be provided at the time when the Corporation becomes aware of such load increases. For the purpose of initiating the report, the Board considers net revenue increases exceeding $500,000 to be material.

The Board recognizes HC's concern respecting the potential for conflict of interest with respect to the allocation of hydro power output from the Taltson facility between NTPC and NTHC. The Board has addressed this matter in the context of the Corporation's code of conduct, under Section 12.1 of this Decision.

9.4 Miscellaneous Revenue

Miscellaneous revenues consist of items such as pole rentals, connection charges, contract work, building and equipment rentals, and connect and disconnect charges.

The HC submitted revenues from contract work are forecast to reduce from the 4-year actual average of $239,000 to $170,000. The HC noted NTPC's explanation that the average was being skewed by $120,000 of contract revenues in Yellowknife in 2004/05.

The HC submitted that given the overall difficulty of forecasting contract work revenues in advance, the actual amounts from the previous 4 years adjusted for the one identified anomaly is the best estimate for these revenues. HC submitted reducing the $120,000 of contract work in Yellowknife in 2004/05 to a more normal $30,000, results in an average of $215,000 of contract work as compared to the $170,000 forecast by NTPC.

NTPC noted HC's recommendation that miscellaneous revenues for both contract work and customer connections should be forecast using a four-year average of the most recent actuals adjusted for anomalies. NTPC estimated that using that methodology results in forecast miscellaneous revenues of $914,000 for 2006/07 and $817,000 for 2007/08. The Corporation indicated it accepts that methodology and the resulting forecasts. (NTPC Reply, p. 32)

Views of the Board

In view of NTPC's concurrence with the HC's proposed method of forecasting miscellaneous revenues, the Board directs NTPC to reflect the revised forecast of miscellaneous revenues in its Phase 1 refiling.

9.5 Impact of Wholesale Contracts on Revenues

The TGC noted that while NUL(YK) has a demand rate of $8.10/KVA for wholesale primary service, there is no corresponding demand charge for NUL (NWT). TGC was concerned if a different set of rates were established as part of the Phase 2 proceedings and in particular a demand charge were instituted for NUL (NWT) the overall revenues could change. In this regard, TGC stated:

> "…These are obviously matters for a Phase 2 proceeding. However, to the extent the absence of contracts with these two large wholesale customers affects the level of rates from these customers it may be a Phase 1 matter. To this end, the TGC recommend the Board direct NTPC to provide, in its Phase 1 GRA Refiling, an assessment of the impact on revenues were a contract signed with the each of the two wholesale customers." (TGC Argument, p. 51 – 52)

In its reply, NTPC submitted TGC appears to be under the misapprehension that entering into wholesale contracts with NUL will impact rates. That is simply not the case. NTPC submitted there are currently no bulk power agreements in place with NUL(YK) and NUL(NWT). NTPC submitted wholesale rates have historically been and will continue to be set by the Board regardless of whether wholesale contracts are ultimately negotiated with NUL. (NTPC Reply, p. 48)

Views of the Board

The Board notes that if the wholesale rate levels or structure were to change as a result of the Phase 2 proceeding or as a result of any contractual arrangements with wholesale customers, the Board will be privy to the revenue impacts of such changes at the time. Accordingly the Board considers no action is required with respect to this matter at this time.

10. STABILIZATION FUNDS

NTPC proposed to continue and maintain its fuel and water stabilization funds, all as active funds. This includes five fuel stabilization funds (Norman Wells, Inuvik, Taltson, Snare-Yellowknife and Diesel communities) and two water stabilization funds (Snare-Yellowknife and Taltson). Subject to the comments below, the Board accepts NTPC's proposed stabilization funds as proposed.

10.1 Water Stabilization Funds

10.1.1 Snare-Yellowknife Water Stabilization Fund

The Snare-Yellowknife water stabilization fund has historically operated on the basis of 177 Gwh as the long term average for hydro generation on the Snare Yellowknife system. In this Application, NTPC requested an increase in the long term average generation to 220 Gwh to reflect the addition of the Bluefish generating plant in 2004/05 (Bluefish as 42.5 GW.h per year and the remaining Snare at 177.5 GW.h per year).

Risks Covered by Water Stabilization Fund

The HC expressed concern that the Snare-Yellowknife water stabilization fund should not have to absorb diesel fuel cost risks associated with hydro or transmission outages:

> "...all diesel generation is automatically run through the Water Stabilization Fund, which was never the intent. In 2005/06, NTPC charged $112,000 to the Fund as a result of work on the Snare Rapids Upgrade and a further $161,000 as result of the tower failure on the Rae Transmission Line. As a

> consequence of the change in 2001/02/03, the Fund operates more like a Fuel Stabilization Fund (volume only) which removes all risks associated with hydro or transmission outages…" (HC Argument, p. 24)

NTPC submitted the Corporation's proposed treatment of diesel fuel expenses for the Snare-Yellowknife and Taltson systems is transparent, consistent with the operating rules of the stabilization funds agreed to by the parties to the 1995/98 Phase 1 Negotiated Settlement and results in the Corporation fairly recovering diesel fuel costs required to maintain safe and reliable service to its customers.

NTPC submitted in the event the Board would prefer an alternative treatment of diesel fuel costs related to unavailability of hydro generation or transmission facilities in the future – along the lines of those suggested by the Hydro Communities, the Corporation should be allowed to consider how it might reasonably implement such a consideration and propose an alternative treatment at a later date. (NTPC Reply, p. 42)

Long Term Average Generation

The HC submitted that the impact of capital additions to the Bluefish plant on the long term average generation of the plant should be addressed by NTPC before the Bluefish generation impacts the water stabilization.

> "In BR.NTPC-19, NTPC was asked to comment on increases to the 42.5 GWh as a result of capital projects at Bluefish. NTPC indicated that the focus of projects to date has been on the safety and condition of Bluefish and not on enhancing the output because the system still had excess hydro capacity. In summary, NTPC indicated that any increases in output would have no impact on test year revenue requirements due to the forecast load being below the 220 GWh system capability. When asked when NTPC would suggest the Board address the Bluefish generation for purposes of the Water Stabilization Fund, NTPC indicated that it would do so following the capital projects that increase output and when the system

> needs hydro power. Although it has no impact today, the Hydro Communities submit that NTPC be required to address the long term output of Bluefish at the time of its next GRA in order to ensure there is a forum to test the long-term output in advance of when the Water Stabilization Fund needs to be updated." (HC Argument, p. 25)

NTPC indicated the Corporation will revisit the long-term average output of Bluefish when it becomes a material consideration in the development of the Corporation's Revenue Requirement. (NTPC Argument, p. 62)

Views of the Board

The Board considers the purpose of a stabilization account is to mitigate the utility's risk for items that are difficult to forecast and where the impacts of variances from forecasts can be significant. In this instance the intent of the water stabilization fund is to mitigate the risk of the availability of the hydro resource for power generation. Given this intent, there does not appear to be a valid reason to insulate NTPC from risks associated with incidents that are not directly related to the availability of the hydro resource.

The Board notes costs associated with hydro plant or transmission outages are generally considered part of the utility's risk. Including such costs and associated risks in the water stabilization account could potentially weaken the utility's incentive to efficiently manage its generation and transmission outages. The Board therefore, concurs with the HC that it would be appropriate to not include the diesel costs associated with generation and transmission outages in the water stabilization account. However, the Board considers the benefits of an approach designed to isolate different risks must be balanced against the administrative costs of implementing it. Therefore, the Board directs NTPC to propose in its refiling, a cost effective approach to excluding the costs and risks associated with generation and transmission outages from the water stabilization account, having regard to the administrative costs involved, and to reflect these proposals, in the refiling.

The Board agrees with the HC that the long-term average generation from Bluefish should be determined as soon as it is practical to do so and before the Bluefish generation impacts the water stabilization fund. Equally, the Board considers given the length of time since the long-term average generation for the Snare system was established this matter should also be revisited on a timely basis. Accordingly, the Board directs NTPC to address the long-term average Bluefish and Snare generation at the time of the next GRA or earlier if the Corporation's forecasts indicate the water stabilization fund might be impacted in any given year.

10.1.2 Taltson Water Stabilization Fund

NTPC proposed to reactivate the Taltson water stabilization fund in order to maintain a parallel fund with the Snare water stabilization fund.

The HC submitted that the level of the surplus hydro available on the Taltson River is still so large that there is no need to establish a fund to deal with water variance from year to year. Therefore, the proposal to reactivate this fund appears to be nothing more than an attempt to further reduce the Corporation's risks.

The HC submitted that the rationale provided for reactivating the Taltson water stabilization fund is not compelling and NTPC's request should be denied. However, should the Board decide to approve this fund, the balance at March 31, 2006 should be deemed to be zero consistent with the fact the fund was deemed to be inactive in the 01/03 Settlement.

NTPC submitted formally reactivating the Taltson stabilization fund with a zero opening balance in the 2006/07 test year is reasonable and should be approved by the Board. NTPC indicated any need to address the related “triggers” for the fund to determine when any refund or riders are required could be suitably addressed during the Corporation’s Phase 2 proceeding.

Views of the Board

The Board is not convinced that there is a need to reactivate the Taltson water stabilization fund at this time given the surplus hydro situation on the Taltson system. However, if this situation is expected to change, NTPC should make an application to reestablish the fund at that time and request approval of the triggers for charges or credits to the fund. Accordingly, the Board directs NTPC to file an application to reactivate the Taltson water stabilization fund when the circumstances surrounding surplus hydro on the Taltson system change, as a result of which NTPC forecasts a need to reestablish the fund.

10.2 Fuel Stabilization Funds

10.2.1 Separate Fuel Stabilization Funds by Community

NTPC operates a single fuel stabilization fund for all diesel communities except for Norman Wells (purchased power) and Inuvik (gas stabilization) for which separate funds are maintained because of the difference in fuel cost causation factors applicable to these latter two communities. The TGC expressed concern that the use of a single fuel stabilization fund and single rider to pass through fuel cost changes for diesel communities is contrary to the premise of community based rates upon which the base rates for each community are established. The TGC submitted that separate fuel stabilization funds should be maintained for each of the communities with separate fuel stabilization riders for the following reasons:

- “Management of a fairly major component of the Revenue Requirement at the time of true-up on a postage stamp basis is inconsistent with the community-based rate making approved by the Board.
- The FSF rider has the impact of averaging fuel efficiencies and delivery costs. Hence, even if there is no difference in the landed cost, the fact that delivery/shipping costs vary significantly as between communities, a common rider results in the cross subsidization. That is, communities with higher delivery/shipping costs are being subsidized by those with lower delivery/shipping costs.
- While the TGC proposal would require a need to develop and maintain riders by community, this is a reality NTPC must live under its presently approved community-based rates. NTPC currently maintains all the information to provide riders by community; hence, development of community-specific FSF riders and implementation of the same should not, in our view, result in an undue additional expense or effort.
- Customer comprehension will be enhanced by a community specific FSF rate rider, not diminished as suggested by NTPC.” (TGC Argument, p. 25)

NTPC indicated the cost of tracking the fuel stabilization fund balance by community would be material.

> “...the Fuel Stabilization Fund has not been tracked on this basis and the history of costs by community cannot be broken out in the fund. Even on a go-forward basis there would be difficulties applying certain common costs, such as fuel hedge costs and credits, on an individual community

> basis. The costs involved in preparing regulatory filings, responding to information requests, and tracking and reconciling riders would be material while providing relatively few cost-tracking benefits. The Corporation has not included any such costs in its test year forecasts and would otherwise charge such costs to the regulatory deferral account. Further, community-by-community riders for fuel cost changes would be complicated to implement and monitor (including the process to turn on/turn off the riders by month for every community), would decrease customer comprehension with respect to the funds and would violate the basic premise for the funds as a collective "insurance" as they were designed in the 1995/98 GRA Negotiated Settlement, with involvement from diesel communities…" (NTPC Reply, p. 43, *ll*. 21 – 32)

Views of the Board

The Board agrees with the TGC that under community based rates, the fuel riders should follow the community costs as closely as possible. The Board notes the increase or decrease in fuel costs that are passed through to customers via the fuel rider would be approximately the same incremental costs per kWh for each community resulting from a common change in the reference price for crude oil. However, given the differences in fuel efficiencies by community as well as differences in station service and line losses by community, the fuel riders to pass through a given cost change can vary by community. For example, a community with a relatively low average fuel efficiency would require a higher fuel rider compared with one with a relatively high fuel efficiency in order to pass through a given cents per kWh increase or decrease in fuel costs. The present fuel stabilization rider mechanism does not recognize these differences by community.

The Board notes NTPC's concern respecting material costs for maintaining separate fuel stabilization accounts by community. However, the Board considers the premise of community based rates can be maintained if the change in fuel cost following a change in the reference price of oil can result in different fuel riders for each community based on the forecast efficiencies and station service/losses for that community. Since the change in the fuel cost on a per kWh basis could be expected to be approximately the same for all communities, there will be no requirement to maintain separate fuel stabilization accounts by community. The reconciliation of revenues and costs recorded in the fuel stabilization account could be carried out as at present using a single fund. The Board directs NTPC to consider these comments and propose a procedure for determining future fuel stabilization riders triggered by fuel price changes as part of the refiling.

10.2.2 Use of Forecast Vs Actual Fuel Efficiencies

NTPC indicated fuel efficiencies are forecast for the test years based on the last three years of actual efficiency, weighted 3 for the highest of the past three years, 2 for the middle efficiency year and 1 for the lowest efficiency of the three years. (Ex 2, p. 2-8, Footnote 8)

TGC submitted that for purposes of calculating the fuel stabilization rider, actual fuel efficiencies rather the forecasts should be used:

> "…As newer engines are installed, any resulting improvement in heat rates is not recognized in the calculation of fuel volumes to the detriment of customers. NTPC should therefore be directed to use actual heat rates in the computation of the FSF Rider." (TGC Argument, p. 27)

NTPC suggested the TGC recommendation would have minimal impact. (NTPC Reply, p. 43)

Views of the Board

The Board considers it appropriate to establish fuel efficiencies on a prospective basis after giving effect to any known changes in fuel efficiencies for the test period such as resulting from the addition of a new generating unit. The Board considers this approach would preserve the utility's incentive to improve efficiencies and is consistent with forward test year regulation. The Board also considers use of forecast efficiencies in the fuel rider calculation would be consistent with the use of forecast efficiencies in the establishment of base rates. Accordingly, the Board accepts NTPC's current practice of using forecast fuel efficiencies for the purpose of determining fuel riders.

11. TERMS AND CONDITIONS OF SERVICE

NTPC proposed a number of changes to its Terms and Conditions of Service "(**TCS**"). The proposed changes are approved with the exception of those noted in the following sections.

After the completion of the Phase 2 GRA, NTPC is directed to amend its terms and conditions of service in accordance with the Board's decisions and to file a copy of the amended terms with the Board. The Corporation should also take steps to advise its customers that the terms and conditions of service have been changed and make arrangements to provide a copy of the revised document to any customer who requests one.

11.1 Application for Service

There was an addition proposed to Section 4.1 (paragraph 4), which would allow NTPC to refuse service to an applicant because a customer in arrears resides at and might continue to reside at the applicant's premises.

Views of the Board

This amendment attempts to make the applicant assume some responsibility for the debt of the previous customer when there may be no legal relationship between these parties. The Board is not convinced that this is an appropriate provision to be included in the TCS and does not approve its inclusion.

11.2 Limitation of the Corporation’s Liability

NTPC proposed a replacement of Section 13.2 by a limitation clause which would prevent any claim for loss, injury or damages brought more than 180 days after the date of the occurrence of the incident which resulted in the loss. The intended effect of this clause is to bar any liability if the claim is made after the 180 day limitation period.

Views of the Board

In the Board’s view, such clauses belong in customer service agreements where the likelihood of notice to the customer is greater.

After questioning in the hearing, NTPC withdrew this proposed limitation period but it should be noted that the Board does not believe that it has the jurisdiction to establish a limitation of actions through the terms and conditions of service which varies from the limitations set out in the NWT *Limitations of Actions Act,* R.S.N.W.T 1988, c. L-8.

NTPC proposed further changes with respect to the text of Section 13.2 in its reply argument. Since this proposed limitation provision will affect all of the Corporation’s customers, the Board does not consider it appropriate to approve a change advanced for the first time in reply argument. The Board therefore directs the Corporation to include this proposed change in its Phase 2 filing in order to give interveners and customers the opportunity to respond to it.

11.3 Indemnity

The Corporation proposed the addition of a new indemnity clause in Section 14.1. This proposed change would require a customer to indemnify the Corporation against certain risks.

Views of the Board

The Board is of the view that such arrangements are best included in customer service agreements where proper notice of the risk assumed by the customer can be given. This amendment is not approved.

11.4 Maximum Investment Policy

NTPC requested approval of revised Maximum Corporation Investment levels of $1,500 per residence, $750/unit for multiple unit residential dwellings and $250/anticipated kW for General Service customers.

NTPC stated that the proposed changes were determined to be reasonable after having reviewed the (i) current corporate investment rates used by other utilities, (ii) NTPC’s current costs to connect new customers and (iii) a net present value analysis of the costs and revenues associated with connecting new customers. Based on that review, NTPC submitted the proposed corporate investment rates are comparable to other utilities, materially less in most sample cases than the costs for hooking up new customers and within levels that can be accommodated for an increase, respectively.

Views of the Board

The Board has reviewed the proposed investment levels and accepts them for purposes of this Decision.

11.5 Standby Interconnection Guidelines

NTPC requested approval of standby interconnection guidelines applicable to any customer who seeks to receive standby service or otherwise self-generate all or a portion of their power while connected to NTPC's distribution system.

Based on comments received at the Technical Workshop, the Corporation withdrew its proposed standby rate design principles until the Phase 2 portion of this proceeding.

The Standby Interconnection Guidelines are set out in Attachment 2 of Chapter 6 of the Application. NTPC indicated the guidelines were prepared in conjunction with Northland Utilities Ltd., allow customers to better evaluate self-generation options and are required by the Corporation for safe and reliable service in the event that standby service is provided.

Views of the Board

The Board notes none of the parties raised any issues respecting the guidelines. The Board has reviewed the guidelines and approves them on an interim basis for purposes of this Decision. The Board will examine the guidelines together with associated rates at the time of the Phase 2 proceedings and consider final approval at that time.

12. OTHER MATTERS

12.1 Code of Conduct

The NTPC has 4 wholly owned subsidiaries:

1. NWT Energy Corporation Ltd.
2. NWT Energy Corporation (03) Ltd.
3. Sahdae Energy Ltd.
4. 5383 NWT Ltd.

With the recent creation of the Northwest Territories Hydro Corporation ("**NTHC"**), NTPC has itself become a wholly owned subsidiary with NTPC's common shares being held by the NTHC.

Without access to the financial statements for these 5 affiliated companies, the TGC is concerned that it is not possible to:

- Gauge the size and results of the affiliates operations;
- Determine the amounts due to/from the NTPC; or
- Assess how the affiliates are being financed and their source of financing.

The TGC is concerned by the lack of transparency and states in its evidence:

> "Without adequate checks and balances to ensure transactions with affiliates are transparent and will not impair the operations of the regulated entity, having the NTPC affiliates engaged in operations similar to those provided by the regulated arm can be problematic. … Clearly, the activities undertaken by NTPC's affiliates are in competition to the

> activities engaged in by NTPC. Therefore, it is appropriate for safeguards to be put in place to ensure the resources of the regulated arm, if used, are properly priced and all such revenues are recorded in the books of the regulated operations." (Ex. 10, p. 3, *ll*. 20 – p. 4, *ll*. 7)

The TGC recommends that NTPC be required to develop a comprehensive code of conduct to govern its transaction with its affiliates. The rationale provided by the TGC is:

> "… A properly structured code of conduct will ensure:
>
> a) regulated operations do not subsidize the non-regulated operations undertaken by the Corporation;
> b) non-regulated subsidiaries do not subsidize the regulated operations;
> c) confidentiality of customer information is protected; and
> d) no preferential access to utility services is provided to the non-regulated operations.
>
> Further, a consistent application of the code of conduct and associated code-compliant reporting of financial results also has the potential to reduce hearing time.
>
> Currently, NTPC appears to provide, on a cost basis, a wide array of services to its subsidiaries, including purchasing, IT support, accounting and commitment of senior management time. In my view, this confers a significant benefit to the non-regulated businesses as these services should be offered on the basis of Fair Market Value (FMV) (i.e. pricing should be no different than if NTPC were providing such services to independent third parties)." (Ex. 10, p. 4, *ll*. 18 – p. 5, *ll*. 6)

The TGC recommends that NTPC is to provide, no later than its next GRA, its own comprehensive code of conduct. The TGC suggests that it could be modeled after the ATCO Group code of conduct. NTPC should also provide sufficient information to determine the exact nature and extent of the types of services provided to affiliates by NTPC, the market prices associated with these services, as well as the method of determining such transfer pricing, the costs of

NTPC senior management time charged to the affiliates and details of all overheads charged for services to affiliates.

The TGC provided substantially more information elsewhere in this process that can be found at the following locations:

- Response to BR.TGC-1
- Hearing Transcripts - Volume 3, Page 13 - Line 4 to Page 52 – Line 14
- Hearing Transcripts – Volume 3, Page 67 – Line 5 to Page 71 – Line 11
- TGC Argument Pages 4-14
- TGC Reply Pages 3-9

As a result of learning about the creation of the NTHC by Bill 4 during the course of this proceeding, the TGC updated the recommendation provided in its evidence to a three-part recommendation:

1. The Board should direct NTPC to adopt a more formalized inter-affiliate code of conduct which would establish principles related to transfer pricing and other matters governing all inter-affiliate transactions.

2. The Board should direct NTPC to file its inter-affiliate code of conduct as soon as possible in 2007, based on a collaborative approach as between NTPC, Board staff, customer representatives, as well as interested stakeholders.

3. The Board direct should NTPC to file, at its next GTA, details of all amounts it incurs in respect of non-regulated operations, basis of these amounts (direct charges as opposed to using allocation factors), allocation

drivers, as well as all amounts included in the Revenue Requirement with respect to costs incurred by non-regulated operations.

The HC is also concerned about Bill 4. The HC explained its concerns in its argument.

> "…Section 36 of Bill 4 calls for an addition to Section 2 of the Public Utilities Act whereby that Act would "not apply to the supply and sale of energy generated by the Twin Gorges Hydroelectric Generating Facility on the Taltson River and any expansion of, addition to or replacement of that Facility, and distributed over transmission lines that have not been constructed on the day this section comes into force." The Public Utilities Act would continue to apply to generation from that facility distributed to customers in and near Enterprise, Fort Resolution, Fort Smith, Hay River and the Hay River Reserve. In short, Bill 4 calls for the existing generation and distribution facilities to continue to be regulated and any expansion facilities to be non-regulated.
>
> This raises several questions. The existing Taltson Hydro Plant includes facilities that would be considered common to it and any expansion facilities such as upstream storage, spillways, other infrastructure and water licenses for example. It is unclear how the costs associated with these common facilities would be shared between the regulated and unregulated operations. Credits from the non-regulated to the regulated operations or adjustments to the rate base would be alternatives.
>
> If a new transmission line is constructed to connect the pilot project or fully reopened mine at Pine Point such as proposed by Tamarlane Ventures Inc., are the sales regulated or unregulated?
>
> How would the revenues from the sale of excess hydro from the existing Taltson Hydro Plant to either the Pine Point pilot/expansion or to the diamond mines be treated?" (HC Argument, p. 5 – 6)

The HC supported the TGC's recommendation on the need for a code of conduct. In its argument, the HC stated that "*Customers require assurance that the regulated operation of the utility is not subsidizing non-regulated affiliates…*".

In its reply, the HC went on to state that "…*the need for a formalized code is increasing in concert with new initiatives and Developments including, most notably, Bill 4 and the creation of the Northwest Territories Hydro Corporation as the new corporate parent of NTPC*."

NTPC's position was that adequate checks and balances exist in NTPC's current procedures to ensure that affiliate transactions are correctly and fairly recorded. The Corporation provided a detailed description of its inter-affiliate cost tracking procedures. NTPC's views on this issue were expressed at various points in this proceeding:

- NTPC Rebuttal Evidence Pages 4 to 9
- Hearing Transcripts – Volume 1, Page 222 – Line 16 to Page 247, Line 19
- NTPC Argument Pages 65 to 68
- NTPC Reply Pages 44 and 45

In its reply, NTPC summed up its position as follows:

> "The Corporation's Written Argument sets out the detailed "checks and balances" and discusses the procedures which it follows when implementing those checks and balances. The Corporation does not oppose codification of its inter-affiliate cost tracking measures and is prepared to make such a filing, based on its review of other applicable jurisdictions, with the Board. It is important to note, however, that a code of conduct in the nature of the ATCO Group code is not relevant (except for the inter-affiliate transfer pricing and cost tracking measures) because the ATCO Group's operating environment, unlike NTPC's operating environment, consists of non-regulated generation and retail functions. As NTPC's regulatory resources will be occupied with the preparation and prosecution of its 2006/08 Phase II GRA over the short term and running parallel proceedings would not be practical, the Corporation suggests that a filing date eight months following a final Phase II decision would be appropriate." (NTPC Reply, p. 44, *ll*. 24 – p. 25, *ll*. 2)

Views of the Board

NTPC's affiliates are becoming involved in increasingly complex and large projects that the Board needs to ensure do not negatively impact upon the regulated ratepayers. Additionally, the creation of the NTHC has exacerbated the already complex relationship that NTPC has with its multiple affiliates.

The Board agrees with the TGC that the NTPC is in need of a comprehensive code of conduct. Given that it is the regulated utility, NTPC, which is typically providing services to its non-regulated subsidiaries (and now potentially its non-regulated parent), merely codifying the Corporation's current cost-tracking measures will not provide the level of transparency and assurance of market-based transactions that is required to protect the regulated ratepayers.

Given the level of concern from the interveners in relation to the passage of Bill 4 and the creation of the NTHC, the Board has undertaken a review of Bill 4 and its implications for NTPC and the regulated ratepayers.

A major effect of Bill 4 was the creation of a new Section 2.1 in the *PUA*. Section 2.1 states:

> **2.1**. (1) This Act shall apply to the supply and sale of energy generated by the Twin Gorges Hydroelectric Generating Facility on the Taltson River and any expansion of, addition to or replacement of that Facility, and distributed to customers in and near Enterprise, Fort Resolution, Fort Smith, Hay River and the Hay River Reserve.
>
> (2) This Act shall not apply to the supply and sale of energy generated by the Twin Gorges Hydroelectric Generating Facility on the Taltson River and any expansion of, addition to or replacement of that Facility, and distributed to customers over transmission lines that have not been constructed on the day

> this section comes into force, unless those lines connect with and branch off transmission lines that had been constructed before that day.

Section 2.1(2) has the effect of creating a single facility, which is both regulated and unregulated at the same time. This will potentially make the regulatory process more complex and difficult due to the Board's requirement to ensure that the unregulated customers are not being subsidized in any way by the regulated customers. Regulated vs. unregulated costs for capital, head office, operations and maintenance, amortization and depreciation, fuel supply, etc. will need to be carefully untangled and closely scrutinized.

Section 2.1(2) does not seem to consider the potential customers north of this new development, which are not industrial. For example, if a deal were made to supply hydro power to Lutsel k'e with a transmission line off the new main transmission line to the diamond mines, it would appear that this transmission line would also be unregulated even though it is providing service to a regulated community. Without a defined franchise area, it is unclear if there is even any obligation to serve these other potential customers.

Section 2.1(2) applies partially based on the time of construction of transmission lines and might have the effect of taking new lines constructed in the existing hydro zone out of Board jurisdiction. Again, the effect could be to have an unregulated transmission line providing service to a regulated community.

While the new Section 2.1 of the *PUA* only refers to the expansion of the Taltson facility, it is clear that the mandate of the NTHC encompasses much more than that single project as Section 5 of Bill 4 states:

5. (1) The objects of the Corporation are:

(a) to generate, transform, transmit, distribute, deliver, sell and supply electricity on a safe, economic, efficient and reliable basis;

(b) to undertake programs to conserve electricity;

(c) to ensure a continuous supply of electricity adequate for the needs and future development of the Northwest Territories; and

(d) to undertake any other activity authorized by the Executive Council.

(2) In addition to the objects referred to in subsection (1), it is an object of the Corporation to facilitate the expansion of, addition to or replacement of the Twin Gorges Hydroelectric Generating Facility on the Taltson River, and to participate in the supply and sale of electricity generated by that Facility.

(3) The Corporation may, with the approval of the Executive Council, establish one or more subsidiaries of the Corporation to carry out its objects.

Not only is there the possibility of additional affiliates being created under Section 5(3), it is the Board's view that Bill 4 places NTPC into direct competition with its own parent company for new power customers. The effect is that there will be a conflict of interest created for the Board of Directors and Senior Management of the two Corporations from the perspective of protecting the interests of the regulated ratepayers. For example, if an opportunity for acquiring a significant new power customer was to arise, would NTPC or NTHC be allowed to pursue the opportunity? How would this decision be made? Where would the interests of the regulated customers be considered and protected in this process?

A decision by the Board and management of the two companies to forgo an opportunity (such as providing power to the diamond mines or other large industrial customers) for NTPC in favor of NTHC could have significant negative repercussions for regulated customers.

As part of its rationale against requiring a code of conduct, NTPC asserted that NTPC's operating environment does not include non-regulated generation and retail functions. The Board disagrees. With the creation of the NTHC, the NTPC operating environment clearly now does include non-regulated generation and retail functions with all the complexity that that entails.

While the Board is not in favor of running parallel proceedings, it is the view of the Board that the development of an NTPC code of conduct cannot wait until the next GRA or even the conclusion of Phase 2 of this GRA. The Board directs NTPC to:

1. By the end of January 2008, file with the Board a formalized inter-affiliate code of conduct which would establish principles related to pricing and other matters governing all transactions with the Corporation's parent, other affiliates and non-regulated operations.

2. As part of its next Phase 1 GRA, file with the Board details of all transactions with the Corporation's parent, other affiliates and non-regulated operations, including details of how the transfer pricing is determined (fair market value, allocated costs), the allocation drivers used, as well as identification of all amounts included in the Revenue Requirement with respect to costs or revenues related to parent, other affiliate and non-regulated operations.

3. By the end of November 2007, file with the Board a detailed policy that explains how the interests of the regulated ratepayers will be protected in

relation to decisions by the Board and Senior Management regarding the operations of NTPC and NTHC. In particular, the Board expects a detailed explanation as to how it will be decided which of the two companies will pursue new generation and sales opportunities and how the interests of the regulated ratepayers will be protected in that decision-making process.

12.2 Generation Using Sources Other Than Diesel

The TGC is recommending that the Board require NTPC to take a more aggressive approach to developing generation sources other than diesel. In its evidence, the TGC stated the following:

> "Customers expect NTPC to take an aggressive and proactive position in pursuit of whatever external funding is available for any green projects that may serve to reduce the dependence on diesel fuel and capitalize on the touted environmental benefits. To this end, NTPC should file quarterly reports of all its efforts to obtain funding from all levels of government to kick start projects to deliver electrical energy from 'green' sources and replace diesel fuel thermal power generation. NTPC should also report on any available private and/or public funding for projects using and exploiting renewable, and/or low-emission energy sources and comment on the viability of such endeavors. Finally, I recommend NTPC also be directed to report on the status of each of the renewable projects noted in TGC.NTPC-9 (c) (iii), pages 4 to 6, as noted above, as well as any other feasible, renewable projects with external funding." (Ex. 10, p. 8, *ll*. 10 – 20)

In its response to BR.TGC-2(b), the TGC clarified its reasons for requesting quarterly reporting by NTPC.

> "The objective in recommending the filing of quarterly reports is to provide the Board and stakeholders with a sense of how proactive and aggressive NTPC has been in the pursuit of federal and territorial funding available for green power. As the Board has broad general and supervisory powers, as

> well as a mandate to ensure prudent acquisition of capital property when first devoted to public use (s. 49 of *Public Utility Act*), the Board may as a result of a review of such quarterly filings direct NTPC to conduct further study, or direct to undertake or not to undertake such projects.
>
> The TGC recognize that approval of capital projects is typically in the context of a GRA; however, given the limited amount of environmentally focused funding, and the many demands placed by various parties for such funding, it may not be appropriate to wait until the filing of the next GRA to seek approval of such projects. As well, we note that NTPC currently has a significant number of potential "green projects" on the table (see TGC Evidence, page 8), which may only proceed if there is some external federal/territorial funding to defray the total costs of these projects. Absent the requested oversight in the form of quarterly reporting, and given the natural incentive for a utility to increase rate base in order to increase its return, there is no real incentive for NTPC to incorporate a "green portfolio" as part of its overall resource planning."

NTPC responded in its rebuttal evidence by stating that there are hurdles with regards to the economic and technical viability of alternative energy projects and that it is NTPC's view that such projects are better pursued by private business and government rather than a Crown Corporation, such as NTPC, as business and government typically have an easier time accessing third-party funding for alternative energy projects. NTPC concluded by stating:

> "…To the extent that Mr. Merani's proposition would require NTPC to aggressively pursue alternative energy funding beyond its current efforts and report quarterly on its efforts to the PUB, NTPC does not have sufficient resources to fulfill this request. NTPC maintains that the current level of effort to acquire third party funding either directly or though assisting communities to obtain funding is appropriate and that quarterly reporting on these efforts would be done at the expense of using resources to successfully acquire funding. If Customers in the diesel communities determine that this is a high priority, NTPC would be willing to amend its 2006/08 rate application to include a position to aggressively and proactively pursue alternative energy funding and make reports to the Board on a full time basis." (Ex. 12, p. 10, *ll*. 40 – p. 11, *ll*. 3)

NTPC added to this statement in its argument.

> "Absent consensus from NTPC's customers that additional resources should be applied to seeking out and reporting on third party funding for alternative energy projects, the Corporation submits that its current program is reasonable and nothing further is required from the Board." (NTPC Argument, p. 69, *ll*. 3 – 5)

The TGC discussed this issue at length in its argument and reply leading to the following summary of the TGC position:

> "NTPC's opposition to take any steps to seek out funding for alternate modes of electricity generation that would wean the thermal communities of their diesel-dependency and reduce fuel costs is contrary to its Vision Statement, and in our view, contrary to its obligation to demonstrate the projects it undertakes from amongst the various alternatives reflect the least short-term and long-term negative environmental impacts. NTPC's argument that it requires additional resources is not plausible given that it has successfully undertaken alternate energy projects in the past without a requirement for additional resources and external funding.
>
> Given the availability of federal and other external funding sources in respect for renewable energy, and the growing societal concerns respecting CO_2 emissions from the use of thermal fuels, NTPC needs to incorporate in its resource planning options a consideration of all of the costs, including impacts of carbon emissions. The Board should direct NTPC to:
>
> i. file quarterly reports of all its efforts to obtain funding from all levels of government to kick start projects that deliver electrical energy from 'green' sources and replace diesel fuel thermal power generation;
>
> ii. report on any available private and/or public funding for projects that use and exploit renewable, and/or low-emission energy sources and comment on the viability of such endeavors; and
>
> iii. report on the status of each of the renewable projects noted in TGC.NTPC-9 (c)(iii), pages 4 to 6 as well as any other feasible, renewable projects with external funding.

> In addition, any GHG credits NTPC becomes entitled to as a result of undertaking renewable energy projects prior to the next GRA, or credits earned from prior such projects, should be recorded in a deferral account for disposition at the next GRA." (TGC Reply, p. 14)

The NTPC position is summarized in its reply as follows:

> "While the TGCs' concerns around alternative energy and climate change is laudable, the TGC fails to recognize that the Corporation shares those concerns and is taking reasonable and prudent measures to address the matter. Consequently, there is no need for the Board to accept the TGCs' recommendations that (i) NTPC be provide with a clear direction to aggressively pursue these funding opportunities and greenhouse credits and (ii) file periodic reports with the Board to document efforts to obtain external sources of capital for the pursuit of alternative projects and developments in climate change credits. Further, as noted in the Corporation's Rebuttal Evidence, "[i]f Customers in the diesel communities determine that this is a high priority, NTPC would be willing to amend its 2006/08 rate application to include a position to aggressively and proactively pursue alternative energy funding and make reports to the Board on a full time basis."
>
> For the reasons discussed in section 4(c) above and in NTPC's Written Argument, the Board should also disregard the TGCs' recommendation that alternative energy projects undertaken before the next GRA be included in a deferral account." (NTPC Reply, p. 46, *ll*. 23 – p. 47, *ll*, 3)

Views of the Board

The Board shares the TGC's concerns with regards to the high cost of power in the diesel communities and supports the development of projects that would alleviate the burden on these communities.

While the Board notes that there have been some large successes by NTPC in lowering its diesel usage, such as the natural gas engines in Inuvik and the purchase of Bluefish, the Board is concerned with the lack of progress in the majority of the small, isolated diesel communities.

The Board is also concerned by the NTPC's apparent willingness to forego some projects in favor of allowing its non-regulated affiliated companies to take the lead with little to no justification being provided to the Board. The Board recognizes there are risks related to the economic and technical viability of certain alternative energy projects and notes NTPC's view that such projects are better pursued by private business and Government rather than a Crown Corporation, such as NTPC. However, the Board notes that NTPC was able to manage such risks in the past through appropriate business arrangements with third parties such as the DPC with respect to the development of hydro on the Snare River. Assuming risk considerations can be addressed through appropriate business arrangements as in the past, the Board expects NTPC to take the lead in aggressively pursuing, from a least cost planning perspective, alternative energy, demand side management and energy efficiency project opportunities while ensuring that project decisions are made in the best interests of NTPC's regulated ratepayers rather than NTPC's affiliates.

The Board finds that requiring NTPC to provide regular reporting on its efforts in the areas of alternative energy, demand side management and energy efficiency projects should not create an undue hardship for NTPC, particularly given that the Board expects the production and evaluation of such reports should be part of NTPC's own internal processes. The Board would, however, be satisfied with biannual reports rather than the quarterly reports recommended by the TGC.

The Board directs NTPC to provide the Board with biannual reports that discuss the following:

1. The efforts and progress of NTPC and its affiliates in pursuing alternative energy, demand side management and energy efficiency projects;

2. Justification for any projects being pursued by NTPC's affiliates rather than NTPC;
3. Funding programs that are, or will be, available and any efforts and progress by NTPC and its affiliates in obtaining funding.

In light of the currently underdeveloped market for the valuation and trading of greenhouse gas emissions, the Board will not act on the TGC recommendation that NTPC create a deferral account to capture the benefits of GHG reductions.

12.3 Accounting Provisions

NTPC indicated there are a number of new provisions in Canadian GAAP that are in effect since the 2001/03 GRA or are emerging and may be in effect over the next few months or years. NTPC indicated, in order to be proactive in addressing the implications for rate regulation, the Corporation is seeking approval and confirmation from the Board to continue to account for various regulatory assets and liabilities consistent with past practice and Board approvals.

The specific accounts referred to by NTPC in this context are

- The rate stabilization funds
- The overhaul deferral account
- Regulatory hearing costs deferral account
- Amortization of financing costs
- Reserve for injuries and damages
- Snare Cascades deferral account
- Employee future benefits deferral account
- Deferred revenues related to customer contributions to aid in the acquisition of property, plant and equipment

- Other regulated assets, comprised of capital studies waiting for capital asset construction or determined not feasible
- The water licensing deferral account
- The treatment of deferring future costs over a period of time, where costs incurred in one year have a longer term benefit to customers and are significant in magnitude (eg. job evaluation)
- Maintaining a liability for the Future Removal for Site Restoration for the removal and clean-up of all its assets regardless of legal obligations or otherwise

The Board confirms the above accounts should be maintained in accordance with past practice and Board approvals and as approved in this Decision.

13. SUMMARY OF BOARD DIRECTIONS

Phase 1 Refiling

1. The Board directs NTPC, in its Phase 1 refiling, to reduce the opening plant balance for 2006/07 by $193,000 being that portion of the rate base addition for the Fort McPherson plant that has not been explained nor demonstrated to be a prudent expenditure by NTPC.

2. The Board directs NTPC, in its Phase 1 refiling, to reduce the cost of the Aklavik plant addition by 50% of the cost increase resulting from the delays. The costs to be included for the 50% risk sharing adjustment are overheads and Allowance for Funds Used During Construction ("**AFUDC**") resulting solely from the delays in completion of the plant caused by the unforeseen length of time spent on community consultations and the fire at Fort McPherson.

3. The Board directs NTPC, in its Phase 1 refiling, to exclude the capital addition related to the plant upgrade amounting to $900,000 from rate base additions for Fort Liard in 2007/08.

4. The Board directs NTPC, in its Phase 1 refiling, to provide a computation of its cash working capital for the test years using the net lead or lag associated with each expense item.

5. The Board directs NTPC, in its Phase 1 refiling, to use a 6% sinking fund return for each of the test years for purposes of calculating the effective cost of long-term debt.

6. The Board directs NTPC, in its Phase 1 refiling, to calculate its effective cost of long term debt as follows:

   Effective Cost of Long Term Debt= (I+AFC-SFE)/(MAD-UFC-SFI)

   Where:
   I= Interest on Mid Year Average Long Term Debt
   AFC= Amortization of Financing Costs
   SFE=Sinking Fund Earnings in the year based on long term averge return of 6%
   MAD=Mid Year Average Debt Principal
   UFC=Unamortized Financing Costs
   SFI=Sinking Fund Investment

7. The Board directs NTPC, in its Phase 1 refiling, to include a capital lease rate that reflects, for the equity portion of lease financing, the fair returns on equity of 9.00% for 2006/07 and 9.25% for 2007/08 less 25 basis points.

8. The Board directs NTPC, in its Phase 1 refiling, to use a fair rate of return on equity of 8.60% for 2006/07 and 9.25% for 2007/08.

9. The Board directs NTPC, in its Phase 1 refiling, to apply a 7% cap on losses.

10. The Board directs NTPC, in its Phase 1 refiling, to calculate forecast station service using the same procedure used for fuel efficiencies. Forecast station service is to be calculated using 3 years of actual data with a weighting of “3” given to the lowest station service year, a weighting of “2” given to the middle station service year and a weighting of “1” given to the highest station service year.

11. The Board directs NTPC, in its Phase 1 refiling, to apply a 5% cap on station service as a percentage of generation.

12. The Board directs NTPC, in its Phase 1 refiling, to provide complete and accurate analyses of the costs and benefits of the AMR projects that incorporate the reasons for and the effects of the redeployment of the linemen. These analyses are to be provided both from the perspective of the individual communities and NTPC.

13. The Board directs NTPC, in its Phase 1 refiling, to remove the 50% net income component of its at-risk compensation program from the revenue requirement calculations for NTPC's regulated business. For 06/07, the amount is $270,000 and, for 07/08, the amount is $279,000.

14. The Board directs NTPC, in its Phase 1 refiling, to calculate its total 06/07 and 07/08 supplies and services expenses using its forecast brushing expenditures of $393,000 for 06/07 and $401,000 for 07/08.

15. The Board directs NTPC, in its Phase 1 refiling, to propose a procedure for returning to the ratepayers over a 3-year period the $345,000 that was over-collected by the Corporation for brushing over the 01/02 to 05/06 period. To be clear, the refunded $345,000 is to be obtained from NTPC's non-regulated cash flow, not by reducing the test year brushing expenditures.

16. The Board directs NTPC, in its Phase 1 refiling, to reconcile the 06/07 and 07/08 Bluefish supplies and services forecasts shown in Tables BR.NTPC-9 and HC.NTPC-13(l) and described in NUL.NTPC-15(b). NTPC is to adjust the Bluefish supplies and services forecasts as needed to account for any errors in their information request responses.

17. The Board directs NTPC, in its Phase 1 refiling, to provide an assessment of the significant and growing gap between the accumulated balance in the

reserve for site restoration and the estimated site restoration costs in light of the above discussion and propose a cap to the accumulated reserve balance until such time as studies on the adequacy of the current balance can be completed.

18. Board directs NTPC, in its Phase 1 refiling, to file a written policy with regards to the criteria that are to be used to determine the eligibility of expenditures for deferral account treatment.

19. The Board directs NTPC, in its Phase 1 refiling, to adjust the test year sales forecasts by community having regard to historical normalized average use per customer and any other relevant factors considered in the top down and bottom up approaches. NTPC is to reflect in the refiling any consequential impacts of any changes in sales forecasts on fuel costs and any other second order impacts.

20. The Board directs NTPC, in its Phase 1 refiling, to reflect the revised forecast of miscellaneous revenues.

21. The Board directs NTPC, in its Phase 1 refiling, to propose a cost effective approach to excluding the costs and risks associated with generation and transmission outages from the Snare-Yellowknife water stabilization fund, having regard to the administrative costs involved, and to reflect these proposals, in the refiling.

22. The Board directs NTPC, in its Phase 1 refiling, to consider these comments and propose a procedure for determining future fuel stabilization riders triggered by fuel price changes.

Phase 2 Application

23. The Board directs NTPC, in its Phase 2 application, to include this proposed change to Section 13.2 of the Terms and Conditions of Service to give interveners and customers the opportunity to respond to it.

Next Phase 1 GRA

24. The Board directs NTPC, in its next Phase 1 GRA, to estimate the revenue lag based on sampling the number of days it takes for recovery of revenues, on average, from customers.

25. The Board directs NTPC, in its next Phase 1 GRA, to address the potential for better matching the carrying cost of the lease to DPC with the cost of the lease to NTPC over the 65-year term of the lease.

26. The Board directs NTPC, in its next Phase 1 GRA, to provide a detailed analysis as to 1) why the fuel efficiencies in Nahanni Butte, Jean Marie River, Sachs Harbour and Colville Lake are so low; and 2) what NTPC has done and will do to improve the fuel efficiencies in these 4 communities.

27. The Board directs NTPC, in its next Phase 1 GRA, to give due weight to the first test year forecast fuel efficiencies in calculating the second test year forecast fuel efficiencies.

28. The Board directs NTPC, in its next Phase 1 GRA, to provide an updated version of Table 5.1 that includes the forecast and actual diesel efficiencies for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.

29. The Board directs NTPC, in its next Phase 1 GRA, to give due weight to the first test year forecast gas efficiency in calculating the second test year forecast gas efficiency.

30. The Board directs NTPC, in its next Phase 1 GRA, to provide an analysis as to why the recent gas efficiency has dropped substantially from 99/00 and 00/01.

31. The Board directs NTPC, in its next Phase 1 GRA, to provide a detailed analysis as to why the actual gas efficiencies are so much lower than the manufacturer's ratings.

32. The Board directs NTPC, in its next Phase 1 GRA, to provide an updated version of Table 5.2 that includes the forecast and actual gas efficiencies for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.

33. The Board directs NTPC, in its next Phase 1 GRA, to include an examination of the pros and cons of separating losses into its two components (electrical losses and non-electrical losses) which would allow the electrical losses to be forecast using the same method as for fuel efficiencies while non-electrical losses could still be forecast using the 5-year rolling average method.

34. The Board directs NTPC, in its next Phase 1 GRA, to provide an updated version of Table 5.3 that includes the forecast and actual losses for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.

35. The Board directs NTPC, in its next Phase 1 GRA, to give due weight to the first test year forecast station service in calculating the second test year forecast station service.

36. The Board directs NTPC, in its next Phase 1 GRA, to provide an updated version of Table 5.4 that includes the forecast and actual station service for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.

37. The Board directs NTPC, in its next Phase 1 GRA, to provide a more detailed analysis of station service levels and potential reductions.

38. The Board directs NTPC, in its next Phase 1 GRA, to undertake a comprehensive review of the at-risk compensation program, make any necessary changes in light of the concerns expressed by the Board and report back to the Board.

39. The Board directs NTPC, in its next Phase 1 GRA, to complete the assessment of the adequacy of the current balance in the accumulated reserve to deal with NTPC's share of anticipated future costs for site restoration including soil remediation and reflect this assessment in the amortization rates.

40. The Board directs NTPC, in its next Phase 1 GRA, to consider, among other forecasting techniques, the use of normalized average use per customer.

41. The Board directs NTPC, in its next Phase 1 GRA or earlier, to address the long-term average Bluefish and Snare generation if the Corporation's

forecasts indicate the water stabilization fund might be impacted in any given year.

42. The Board directs NTPC, in its next Phase 1 GRA, to file with the Board details of all transactions with the Corporation's parent, other affiliates and non-regulated operations, including details of how the transfer pricing is determined (fair market value, allocated costs), the allocation drivers used, as well as identification of all amounts included in the Revenue Requirement with respect to costs or revenues related to parent, other affiliate and non-regulated operations.

Other Directions

43. The Board directs NTPC, in its dealings with contractors, to establish prudent contractual arrangements including the reasonable provisions for insurance and guarantees of proper workmanship and materials that a prudent owner would require.

44. The Board directs NTPC to ensure that the Governance and Compensation Committee is exclusively made up of independent directors.

45. The Board directs NTPC that, commencing with the 06/07 test year, NTPC's 3-year rolling average actual brushing expenditures must be no less than 10% below the 3-year rolling average forecast brushing expenditures. NTPC's 5-year rolling average actual brushing expenditures must be no less than equal to the 5-year rolling average forecast brushing expenditures.

46. The Board directs NTPC to provide to the Board and to all interested parties a report on the costs and revenues associated with new industrial, mining or

wholesale loads, or load increases, that would have a material impact on its level of earnings and/or rates. This information should be provided at the time when the Corporation becomes aware of such load increases. For the purpose of initiating the report, the Board considers net revenue increases exceeding $500,000 to be material.

47. The Board directs NTPC to file an application to reactivate the Taltson water stabilization fund when the circumstances surrounding surplus hydro on the Taltson system change, as a result of which NTPC forecasts a need to reestablish the fund.

48. The Board directs NTPC, after the completion of the Phase 2 GRA, to amend its terms and conditions of service in accordance with the Board's decisions and to file a copy of the amended terms with the Board. The Corporation should also take steps to advise its customers that the terms and conditions of service have been changed and make arrangements to provide a copy of the revised document to any customer who requests one.

49. The Board directs NTPC, by the end of January 2008, to file with the Board a formalized inter-affiliate code of conduct which would establish principles related to pricing and other matters governing all transactions with the Corporation's parent, other affiliates and non-regulated operations.

50. The Board directs NTPC, by the end of November 2007, to file with the Board a detailed policy that explains how the interests of the regulated ratepayers will be protected in relation to decisions by the Board and Senior Management regarding the operations of NTPC and NTHC. In particular, the Board expects a detailed explanation as to how it will be decided which of the two companies will pursue new generation and sales opportunities and how

the interests of the regulated ratepayers will be protected in that decision-making process.

51. The Board directs NTPC to provide the Board with biannual reports that discuss the following:

1. The efforts and progress of NTPC and its affiliates in pursuing alternative energy, demand side management and energy efficiency projects;
2. Justification for any projects being pursued by NTPC's affiliates rather than NTPC;
3. Funding programs that are, or will be, available and any efforts and progress by NTPC and its affiliates in obtaining funding.

14. BOARD ORDER

NOW, THEREFORE IT IS ORDERED THAT:

1. The Board directs NTPC to provide to the Board and interested parties a Phase 1 refiling reflecting the findings and directions in this Decision within 30 days of this Decision.

2. The Board directs NTPC to provide as part of the Phase 1 refiling a working model, in Excel format, of all GRA schedules relating to the establishment of rate base, return, revenue requirement, revenues and revenue deficiencies and all relevant supporting schedules.

3. Nothing in this Decision or Order shall bind, affect or prejudice this Board in its consideration of any other matter or question relating to Northwest Territories Power Corporation.

ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES

Joe Acorn
Chairman

DATED August 29, 2007

Union Gas Ltd. and Enbridge Gas Distribution Inc. A Review of the Board's Guidelines for Establishing Their Respective Return on Equity – Decision and Order RP-2002-0158

Ontario Energy Board
Commission de l'Énergie de l'Ontario

RP-2002-0158

IN THE MATTER OF APPLICATIONS BY

UNION GAS LIMITED

AND

ENBRIDGE GAS DISTRIBUTION INC.

FOR

A REVIEW OF THE BOARD'S GUIDELINES FOR ESTABLISHING THEIR RESPECTIVE RETURN ON EQUITY

DECISION AND ORDER

2004 January 16

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2002-0158 1

EB-2002-0484

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S.O.1998, c.15, Schedule B; 2

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, transmission, distribution, and storage of gas; 3

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, transmission, distribution, and storage of gas; 4

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. and Union Gas Limited for a review of the Board's Guidelines for establishing their respective return on equity. 5

BEFORE: 6

Paul Vlahos 7
Presiding Member

Bob Betts 8
Member

Paul Sommerville 9
Member

DECISION AND ORDER 10

January 16, 2004 11

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The Applications 15

Union Gas Limited ("Union") filed an application for rates dated May 27, 2002 with the Ontario Energy Board, under section 36 of the *Ontario Energy Board Act, 1998 S.O. 1998*, c.15, Schedule B (the “Act”). Union filed evidence in support of its application on June 25, 2002. The Board assigned file number RP-2002-0130 to Union’s application. By letter dated August 1, 2002, Union added to its application a request for changes to the Board’s formula used to establish Union’s return on common equity (“ROE”). 16

Enbridge Gas Distribution Inc. (“Enbridge” or “EGDI ”) filed an application for rates dated September 2, 2002, with the Board, under section 36 of the Act. Included in its application was a request for a change to the Board’s formula used to determine EGDI’s ROE. The Board assigned file number RP-2002-0133 to the EGDI application. 17

The Proceeding 18

The evidence in relation to the ROE issue relied upon by Union and EGDI in their applications is essentially the same, and both Applicants rely upon the same consultant, Ms.K. McShane. With the consent of the Applicants, the Board decided to hear the ROE issue raised in the two applications in a separate stand-alone proceeding. The Board assigned file number RP-2002-0158 (EB-2002-0484) to this separate ROE proceeding. 19

On December 16, 2002, the Board issued Procedural Order No. 1 setting out the schedule for the proceeding. In accordance with that order, Union filed on February 7, 2003 updated evidence prepared by Ms. McShane. 20

Procedural Order No. 2 issued on March 3, 2003 amended the dates for the proceeding as follows: interrogatories on the Applicants’ evidence were due on April 11, 2003; interrogatory responses were due on April 29, 2003; supplementary interrogatories on the Applicants’ evidence was due on May 8, 2003 and responses to supplementary interrogatories, were due May 15, 2003; an Issues/ Technical Conference was to be held on May 21, 2003; an Issues Day proceeding was to be held on May 23, 2003; intervenor evidence was to be filed by June 27, 2003; interrogatories on intervenor evidence were due by July 11, 2003; interrogatory responses were due by July 25, 2003. 21

Procedural Order No. 3 issued on April 30, 2003 cancelled the Issues/Technical Conference and the Issues Day and specified that a Stakeholders Conference take place on May 23, 2003. Procedural Order No. 4 issued on July 3, 2003 set the commencement of the hearing as September 18, 2003. On August 12, 2003 the Board issued Procedural Order No. 5 which revised the hearing date to September 22, 2003. 22

The Hearing 23

The oral proceeding commenced on September 22, 2003, and concluded on September 26, 2003 after 5 hearing days. 24

The Applicants filed their written argument-in-chief after the close of business October 20, 2003, rather than October 17, 2003 as originally scheduled. Consequently, some intervenors requested a corresponding extension to file their reply argument, which the Board granted. Six intervenors filed their arguments by November 5, 2003. The Board also extended the date on which the Applicants' reply argument was due from November 7, 2003 to November 12, 2003. At the request of the Applicants, the Board further extended the filing date from November 12 to November 21, 2003. 25

Parties and their Representatives 26

Below is a list of parties and their representatives who participated actively by leading evidence or cross-examining witnesses in the oral hearing, or by filing argument. 27

28

Union Gas Limited	Michael Penny
	Marcel Reghelini
Enbridge Gas Distribution Inc.	Helen Newland
	Marika Hare
Board Counsel	Patrick Moran
Consumers Association of Canada ("CAC")	Robert Warren
London Property Management Association ("LPMA")	Randy Aiken
Industrial Gas Users Association ("IGUA")	Peter Thompson
Vulnerable Energy Consumers Coalition ("VECC")	Michael Janigan
Energy Probe	Brian Dingwall
Pollution Probe	Murray Klippenstein
Ontario Public School Boards' Association ("OPSBA")	Jay Shepherd
Canadian Gas Association ("CGA")	Laurie Smith

Witnesses 29

The Applicants called the following witness: 30

Kathleen McShane	Senior Vice President, Foster and Associates

IGUA/VECC/CAC called the following witness: 31

Lawrence Booth	Professor of Finance, Rotman School of Management, University of Toronto

32

33

CGA called the following witnesses:

Peter Case	Peter Case Consulting
Michael Cleland	President and Chief Executive Officer, Canadian Gas Association

34

The Board called the following witness:

William Cannon	Associate Professor of Finance, School of Business, Queen’s University

Submissions and Exhibits 35

36

Copies of the evidence, exhibits, arguments, and a transcript of the proceeding are available for review at the Board’s offices.

37

The Board has considered the evidence, submissions and arguments in the proceeding, but has summarized the evidence and the positions of the parties only to the extent necessary to provide context for its findings.

38

The Board, with industry participation, has developed standards and processes for the electronic regulatory filing (“ERF”) of evidence, submissions of parties, Board orders and decisions. This Decision and Order will be available in ERF form shortly after initial copies are issued in hard copy. The ERF version will have the same text and numbered headings as the initial hard copy, but may be formatted differently.

2 SUMMARY OF CURRENT GUIDELINES 39

40

The Ontario Energy Board currently uses a formula based approach to set the return on common equity (“ROE”) for most gas utilities under its jurisdiction. The Board’s approach is set out in its *Draft Guidelines on a Formula-Based Return on Common Equity* (“ROE Guidelines”). The ROE Guidelines were first applied in the EBRO 495 proceeding which set fiscal 1998 rates for The Consumers’ Gas Company Ltd. (now EGDI).

41

The ROE Guidelines start with the establishment of a benchmark ROE to provide, as it was described in the EBRO 495 decision, “a just and reasonable return on equity” for each gas distribution company. This benchmark ROE is then adjusted for each subsequent fiscal year in accordance with an adjustment mechanism.

42

The benchmark ROE for a utility is set by taking the forecast yield for long-term Government of Canada bonds and adding an appropriate risk premium to account for the utility’s risk relative to the long-term Government of Canada bonds. The equity risk premium test is used to determine the appropriate risk premium.

43

The Compendium to the ROE Guidelines, at p.5, described this method as follows:

44

> The equity risk premium test is also designed to measure the cost of equity capital from the capital attraction perspective. It relies on the assumption that common equity is riskier than debt and that investors will demand a higher return on shares, relative to the return required on bonds, to compensate for that risk. The premium required by an investor to assume the additional risk associated with an equity investment is taken to be the difference between the relevant debt rate, usually the yield on long-term government bonds, and some estimate of the stock's cost of equity. The recommended cost of equity value under the equity risk premium approach is therefore usually computed as the sum of the test-period forecast for the government yield and the utility-specific risk premium the analyst has estimated based on historical equity risk premium evidence and forward-looking considerations.

45

The benchmark ROE becomes the allowed ROE for the first year. EGDI’s benchmark ROE was set at 10.65% in the EBRO 495 proceeding, based on a risk premium of 340 basis points. Union’s benchmark ROE was set at 11.00 % in the EBRO 493-04/494-06 proceeding, based on a risk premium of 355 basis points. The 15 basis points difference reflects the relative risk of the two utilities. The difference of the returns over 15 basis points is accounted for by the difference in the timing of setting the rate or return for the two utilities.

46

Once the benchmark ROE has been established, the allowed ROE is automatically adjusted annually, using a formula. The change in the forecast yield for long-term Government of Canada bonds is multiplied by a factor of 0.75 to determine the adjustment to the allowed ROE. This adjustment factor is then added to the utility’s previous test year ROE and the sum is rounded to two decimal points to produce the new ROE.

47

<u>Example:</u>

Allowed ROE for test year 1		10.00%
Test year 2 long-term Government of Canada bond yield forecast	5.00%	
Test year 1 long-term Government of Canada bond yield forecast	<u>5.25%</u>	
change in interest rates	-0.25%	
adjustment factor of 0.75 applied		<u>0.1875%</u>
ROE for test year 2		9.8125%
Approved ROE for test year 2 (rounded to 2 decimal places)		9.81%

Regarding the need for review in the future, the ROE Guidelines, in the Compendium at p. 28, state: 48

> The Board believes that the rate of return formula should be reviewed as conditions arise that may call into question its validity (e.g., a change in the relative taxation of the income from debt and equity investments, or a fundamental change in business or financial market conditions). To set a particular time period may be artificial and necessitate an unnecessary review or stifle a review at another time when an adjustment would be appropriate. Parties to a proceeding may ask the Board to review the formula when they feel it is appropriate or the Board may do so on its own initiative. In either case it will be the Board’s decision as to the time for a review. 49
>
> From time to time the Board may request the presentation of other tests or require some weighting for other tests in the formula should the Board want to assure itself that the equity risk premium formula approach does not lead to perverse results and is directionally in line with other market indicators.

3 EVIDENCE AND POSITIONS OF THE PARTIES 50

The Applicants 51

The Applicants relied on Ms. McShane's evidence, in support of their request for a new benchmark 52
ROE and a change to the annual adjustment formula.

Ms. McShane concluded that the ROE Guidelines produce an ROE for EGDI and Union that is 53
unreasonably low. This conclusion was based upon her proposed methodology, her analysis of changes in the Canadian bond market since March 1997, and her consideration of the allowed returns for U.S. gas and electric utilities.

To formulate her recommendation for a new benchmark ROE in the range of 11.5 - 11.75%, based 54
on a forecast 6.0% yield for long-term Government of Canada bonds, Ms. McShane applied three equity return tests; the Equity Risk Premium (ERP) test, the Discounted Cash Flow (DCF) test and the Comparable Earnings (CE) test.

Ms. McShane used three versions of the ERP test which produced an ROE range of 10.5% to 11.25%. 55

Ms. McShane's DCF test, which she applied exclusively to a sample of U.S. utilities, produced an 56
ROE of 11.5%.

Ms. McShane applied her CE test to both Canadian and U.S. industrial returns covering the 1992- 57
2001 period, and giving primary weight to the Canadian evidence, this produced an ROE range of 12.75 - 13.25%.

Ms McShane then combined these results, weighting the ERP and DCF test results 37.5% each, and 58
the CE test results 25%, to produce her recommendation that an appropriate benchmark ROE would be in the range of 11.5 - 11.75% for an average risk utility. She recommended the mid-point of 11.625% as an appropriate benchmark ROE for Union, as an average risk utility, and 11.5% for EGDI, as a slightly lower risk utility.

Ms. McShane noted that the regulated ROE for U.S. gas and electric utilities were typically higher 59
than for utilities in Canada. She was of the view that this divergence could disadvantage Canadian utilities and their shareholders within the context of an increasingly integrated North American capital market environment.

Ms. McShane also pointed to a number of changes that had occurred in the bond and equity markets 60
after the ROE Guidelines were established, which she relied on to support her contention that the risk premiums used to set the original benchmark ROE for the Applicants are too low in today's context.

CGA 61

The CGA sponsored the evidence of Mr. Cleland and Mr. Case. Mr. Cleland was presented as a policy spokesperson for the CGA and his evidence was limited to confirming that the CGA supported a higher ROE for Canadian utilities, including the Applicants. 62

Although Mr. Case did not propose any changes to the current ROE formula or the annual adjustment mechanism, his view was that an ROE in the range of 10.5 - 11.0% would be viewed by equity markets as a fair return, based on his telephone discussions with various equity market participants and analysts. 63

His recommendation was based on the following five factors. 64

First, Mr. Case claimed that the formula no longer compensates investors appropriately for an increase in the perceived riskiness of utilities since 1997. 65

Second, according to Mr. Case, recent market conditions limit the usefulness of the Capital Asset Pricing Model (CAPM) because market conditions have artificially depressed utility stock betas. 66

Third, he suggested that the continuing globalization of capital markets since the Board issued its 1997 ROE Guidelines has made a comparison to higher US utility returns more relevant. The lower returns of Canadian utilities put them at a competitive disadvantage in attracting capital. Mr. Case pointed to the recent sale by Aquila Inc. of its Canadian utility as an example of an investor not willing to invest in a utility in British Columbia or Alberta because the ROE was too low. He also pointed to some examples of Canadian utility holding companies that experienced difficulty in raising common equity as a further demonstration that the current level of ROE for Canadian utilities was a problem. 67

Fourth, with the significant decline in bond yields since 1997, the formula has resulted in a decline in equity returns that is faster than the decline in the utilities' embedded cost of debt. As a result, there has been downward pressure on utility interest coverage ratios, which in turn puts pressure on utility debt ratings. 68

Finally, Mr. Case believed that the majority of institutional equity investors view the returns currently generated by the formula based approach used by the Board and other Canadian regulators as inadequate. 69

CAC, IGUA and VECC 70

CAC, IGUA and VECC sponsored the prefiled report prepared by Drs. Booth and Berkowitz. The authors concluded that a fair ROE for the Applicants is in the range of 8.5%, which includes a 50 71 basis point "cushion" above their estimates of the cost of attracting capital for these utilities. Only Dr. Booth testified in the hearing but he adopted the joint prefiled evidence.

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In their report, Drs. Booth and Berkowitz came to their ROE recommendation by applying two versions of the ERP test and giving equal weight to the results. Their first ERP test was the single-factor Capital Asset Pricing Model (CAPM), while their second ERP test relied on a two-factor model which differentiated between the systematic risk due to changes in the equity market and changes in security returns due to fluctuations in interest rates.

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Their application of the CAPM model yielded an ROE in the range of 8.02% to 8.47%. This was based on their assessment that (1) the market risk premium is now 4.5% and (2) a reasonable range for the beta risk of an average-risk regulated Canadian utility is 0.45 to 0.55.

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Applying their two-factor model, which incorporates a term premium estimate of 1.00%, produced an ROE in the range of 7.66% to 7.74%.

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In further support of their proposed benchmark ROE of 8.5%, Drs. Booth and Berkowitz produced DCF test results, based on a sample of U.S. utilities, that pointed to an ROE in the range of 7.89 to 8.57%.

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In testimony, Dr. Booth indicated that he did not see a need to move away from the Board's ROE Guidelines, even though their analysis suggested that the ROE Guidelines produced an ROE that was more generous than it needed to be. In their report, Drs. Booth and Berkowitz stated their belief that the 75% adjustment factor was a reasonable compromise between (a) assuming that the overall required return on the stock market is independent of long-term Government of Canada bond yields implied by a 50% adjustment coefficient, and (b) assuming that the riskiness of the long-term Government of Canada bond relative to the equity market is constant, as implied by a 100% adjustment factor.

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Finally, Drs. Booth and Berkowitz pointed out that the market-to-book-value ratios of all Canadian utilities, save one, were well in excess of 1.0. They stated that this was a clear indication that utilities have not suffered a loss of financing flexibility since Canadian regulators moved to automatic ROE adjustment mechanisms based on long-term Government of Canada bond yields, beginning in 1994.

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Dr. Cannon

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Dr. Cannon was retained by the Board to provide additional evidence on the ROE issues. He prepared a report that was provided to all parties and he answered interrogatories on his evidence. He also appeared as a witness and was cross-examined by the parties. His expert opinion, as with the other expert witnesses, was provided to the Board entirely on the public record.

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In his evidence Dr. Cannon concluded that there had been a substantial decline in the equity capital costs for the average-risk Canadian gas utility and for Ontario's major gas distributors since 1996.

According to Dr. Cannon, there is no evidence to suggest that the application of the Board's ROE formula methodology had resulted in allowed returns which had violated either the fair return or financial integrity standards of regulatory rate setting. 81

He also submitted that the decrease in ROE under the ROE Guidelines had been less than it would have been, applying the capital attraction standard of regulatory rate setting instead. 82

It was Dr. Cannon's view that an appropriate benchmark ROE for the average-risk Canadian energy utility now lies in the range of 7.5% to 7.9%, lower than the ROE that would currently be produced under the ROE Guidelines. Dr. Cannon's benchmark ROE recommendation is based primarily on results from using the three equity return tests that Ms. McShane used. In using those tests, he applied different judgment and reached different conclusions than Ms. McShane did. 83

Using his ERP test, Dr. Cannon concluded that an appropriate ROE would be in the range of 6.35-6.55% for the average-risk Canadian energy utility, based on a mid-June estimate of 4.00% for the yield on a truly riskless long-term Canadian asset and a corresponding "all-in ERP" in the 2.35-2.55% range. His utility ERP test findings reflected the substantial decline in the prospective market risk premium in recent years as well as the continuing low relative investment riskiness of the typical energy utility. 84

Applying the DCF test to a sample of Canadian energy utilities produced a benchmark ROE in the range of 7.9% to 8.5%. 85

The CE test, using data for Canadian industrials over the 1991-2002 period produced an ROE of 10.2% for Dr. Cannon. 86

To arrive at his final recommendation for a benchmark ROE, Dr. Cannon applied different weights to his three test results than Ms. McShane. Dr. Cannon weighted his results from the three tests as follows: ERP - 60%, DCF - 15%, and CE - 25%. 87

Dr. Cannon's ROE recommendation reflected an "all-in benchmark ERP" of 2.93% above the long-term Government of Canada bond yields prevailing in mid-June. 88

With respect to the adjustment formula, Dr. Cannon proposed that the adjustment factor applied to changes in the forecast long-term Government of Canada bond yields be reduced to 70%, from the current 75% value. He based this on his view of the sensitivity of his equity return tests to changes in the long-term Government of Canada bond yields and his weighting of the three tests. 89

Dr. Cannon concluded that, all other things being equal, the ROE numbers produced by the ROE Guidelines in recent years are likely too high. 90

LPMA 91

LPMA did not rely on the evidence of any particular expert as, in its opinion, the analysis of any 92 one expert did not produce a definitive estimate of a fair return. Instead, LPMA gave equal weight to the results of the work done by Ms. McShane, Dr. Cannon and Drs. Booth and Berkowitz, with one exception. LPMA argued that zero weight should be given to Ms. McShane's CE test because, in the view of LPMA, the market risk premium was overstated.

LPMA's final recommendation for a new benchmark ROE was 8.96% based on giving equal weight 93 to the three expert's evidence, removing the CE test, applying a market risk premium of 325 basis points, and averaging the three ERP estimates produced by Ms. McShane, Dr. Cannon and Drs. Booth and Berkowitz.

LPMA submitted that the CE test should not be relied on because of the difficulty in assembling an 94 acceptable sample of comparable companies against which to assess the regulated utility. First, LPMA noted that both Dr. Cannon and Ms. McShane selected comparable industrials yet the results were 300 basis points apart. Second, there had been debate regarding the appropriate earnings to use and widespread concern regarding corporate reporting which placed the accuracy of the information in doubt. Third, the American returns were not suitable comparators as the American economy was generally more competitive resulting in higher risks and consequently higher returns. Fourth, LPMA noted that Canadian regulators often gave little or no weight to the CE test.

School Boards 95

School Boards also did not call any evidence. School Boards recommended that the Board approve 96 an ROE of 9.0% for EGDI, assuming a risk-free rate of 5.4%.

With respect to Union Gas, School Boards believed that there was no evidence to suggest that Union 97 Gas was any riskier that EGDI. The premium paid by Duke when it acquired Union suggested that Union was not as risky as Ms. McShane or Dr. Cannon believed. Further, the fact that the two utilities are at the same deemed equity ratio implied that they could be considered to be at the same risk level. Therefore, School Boards submitted that the Board should approve an ROE of 9.0% for Union Gas as well.

School Boards noted that the debate of the experts demonstrated that the same underpinning numbers 98 could produce different results. Therefore the expert evidence was suspect, as all of the experts chose and manipulated data in ways that limited the objectivity of their conclusions. The School Boards argued that, given this uncertainty among experts regarding the appropriate ROE tests, greater weight should be placed on evidence other than that of the experts.

School Boards' position was therefore not tied to that of the experts. Instead it proposed a different 99 approach. School Boards proposed five tests to arrive at its 9.0% ROE recommendation.

The first test, named the “mind experiment”, consisted of arriving at a number representing the intersection of the experts’ broadest ranges of ROE. 100

The second test, using the Seigel Tables, implied a long term market return for utilities of 7.56% to 7.74% if compound returns were used. If arithmetic mean returns were used, then the resulting ROE would be in the range of 8.46% to 8.72%. 101

The third test, based on expectations of pension funds, suggested that utility ROE should be no more than 8.5%. 102

The fourth test, the premium paid by Duke, Union’s parent company, demonstrated that the current ROE resulting from the formula was somewhat high. According to School Boards, assuming that the current ROE was too high by 50 basis points, the resulting ROE would be 8.76 for EGD and 8.91% for Union Gas. 103

The fifth test, a simple average of the experts’ recommendations, resulted in an ROE of 9.05%. 104

Combining these five approaches led School Boards to recommend a new benchmark ROE of 9.0% for both Applicants. 105

With respect to the adjustment mechanism, the School Boards supported the proposal of the Applicants to adjust the ROE annually by 50% of the change in the forecast long-term Government of Canada bond yields. 106

Energy Probe 107

Energy Probe also did not rely on the evidence of any particular expert. It submitted that there was no need to make any changes to the ROE Guidelines and that the ROE Guidelines should be re-affirmed to signal stability and predictability in Ontario’s natural gas environment. 108

Energy Probe submitted that there was no evidence that the Applicants had suffered any capital shortage under the current ROE Guidelines. In fact, the formula seemed to provide adequate consideration of costs related to maintaining access to capital markets. Furthermore, it was not necessary to make changes to the ROE formula to address changes to business and financial risk because other mechanisms, such as deferral accounts, were available to the Board for this purpose. 109

Energy Probe suggested that the actual financial performance of utilities demonstrated that they were low risk enterprises and that the argument for any alteration to the ROE formula was weak. Energy Probe noted that over the last decade, both utilities had consistently outperformed the Board allowed ROE. 110

Pollution Probe 111

Pollution Probe did not address the issue of the appropriate ROE formula. Rather it requested that the Board permit the Applicants to earn an additional ROE, over and above what the ROE Guidelines would produce, as an incentive to aggressively promote cost effective energy conservation and efficiency. 112

4 BOARD FINDINGS 113

The Board's ROE Guidelines suggest that there are two reasons which would justify a review of the formula. The first justification would be significant changes in market conditions. The second justification would be significant changes in the utility risk. The Applicants have based their request for a review on their assertion that there have been significant changes in the capital markets. There is no claim that the utility risk per se has increased. The Board recognizes that the ROE Guidelines are not binding and that it is always open to a party to propose a new approach. The Applicants have made such a proposal and the Board has considered on its merits. 114

The first issue for the Board is whether the adjustment mechanism contained in the current ROE Guidelines produces a prospective return on common equity that continues to be appropriate. The formula in the current guidelines produces an ROE of 9.71% for Enbridge and 9.86% for Union at a long-term Government of Canada bond yield of 6.00%. This reflects a risk premium of 371 basis points for Enbridge and 386 basis points for Union. At a long-term Government of Canada bond yield of 6.00%, the Applicants are asking the Board to set a new benchmark ROE of 11.50% for Enbridge and 11.65% for Union. This proposal reflects an increase in the risk premium to 550 basis points for Enbridge and 565 basis points for Union. They are asking the Board to move from sole reliance on the equity risk premium (ERP) test, as set out in the ROE Guidelines, to weighted reliance on three tests described in Ms. McShane's evidence: the ERP test (37.5%), the discounted cash flow (DCF) test (37.5%) and the comparable earnings (CE) test (25%). 115

The second issue for the Board is the Applicants request, based on Ms. McShane's evidence, for a change to the annual adjustment formula, so that in each succeeding year, the ROE is adjusted by 50% of the change in the forecast yield for long-term Government of Canada bonds, rather than the 75% required by the ROE Guidelines. However, this request was contingent upon the outcome of the first issue. 116

The third issue for the Board is the request by the Applicants, based on Ms. McShane's evidence, that the factor representing the yield spread between the 10 and 30 year Government of Canada bonds be fixed, rather than being calculated annually. Dr. Cannon makes the same suggestion, although he recommends a lower spread than Ms. McShane. 117

First, we will deal with the primary issue of whether a new benchmark ROE should be established for EGDI and Union. 118

In approving or fixing rates, the Board derives its jurisdiction from section 36 of the Act. Pursuant to that section, the Applicants can only charge rates for the distribution of gas with the approval of the Board. The burden of proof to demonstrate that the rates applied for are just and reasonable lies with the Applicants. The setting of just and reasonable rates involves the balancing of the interests of the Applicants, on the one hand, and the ratepayers, on the other hand. Rates will be just and reasonable when the ratepayers are paying a fair price for the distribution services that they receive and the Applicants have an opportunity to earn a fair return on their invested capital. Allowance for 119 a prospective fair return on common equity is therefore a component of establishing just and reasonable rates.

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Section 36 (3) of the Act provides that the Board can adopt any method or technique for the setting of rates that it deems appropriate. The method to be adopted is at the Board's discretion, which the Applicants, the expert witnesses and other parties acknowledge. Currently, for the purpose of establishing the ROE for a utility, the Board uses a formula based approach, as set out in the ROE Guidelines, based on the ERP test. The institution of this formula and its application dates back to 1997. None of the parties have proposed that the Board should move away from a formula based approach. We are of the view that it is appropriate to continue with a formula based approach because it provides a significant degree of predictability and is compatible with both cost of service and performance-based regulation.

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A great deal was made in the hearing by Ms. McShane and the Applicants about comparisons with American utilities and returns awarded by other Canadian jurisdictions. The Applicants argue that the returns of American utilities are higher and that this supports the need for higher returns for the Applicants. They also cite decisions by certain Canadian regulators in support of higher returns. Yet, they also argue that the Board should not be influenced by the unfavourable decisions for recalibrating the existing formula by certain other Canadian regulators, on the basis that this Board should lead rather than follow. Also, they state that the Board must consider the applications on their own merits.

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Discussions of ROE decisions from other jurisdictions invariably come into the evidence and arguments of parties. We continue to view such evidence as informative. However, we do not believe that decisions in other jurisdictions are determinative of what ought to be a prospective fair ROE for Ontario utilities. There are many reasons why ROE may differ from one jurisdiction to another in North America. These may include differences in legislation, timing, tax laws, accounting practices, risk considerations arising from different capital structures and from regulatory practices which may or may not shield the utility from business or weather risks, and other regulatory considerations unique to each jurisdiction, including varying reliance on the common tests for determining a fair ROE. There was no evidence that would allow the Board to make a meaningful comparison of these factors, including the relative riskiness of Canadian and American utilities, in order to understand the difference in ROE between American and Canadian utilities. The bare fact that American utilities might earn a higher ROE than Canadian utilities, as suggested by Ms. McShane and argued by the Applicants, is an inadequate basis upon which to determine whether the ROE for the Applicants should be increased to a level similar to the ROE for American utilities. Similarly, the fact that some Canadian regulators may have awarded higher or lower returns than the Ontario Energy Board, while informative, is not determinative for largely the same reasons.

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Ms. McShane suggested that the difference in ROE between American and Canadian utilities was a factor that could create a disadvantage for Canadian utilities and their shareholders. However, we find no evidence to suggest that such a disadvantage currently exists or is likely. Mr. Case suggests that Union, for example, must now compete for equity capital with the other global subsidiaries of Duke Energy, Union's parent; if Union cannot offer a competitive return with the other units, capital might be more difficult to obtain from the parent company. There was no evidence before the Board to suggest that the Applicants are experiencing any difficulty in raising equity capital from or through their respective parents.

A long standing regulatory principle espoused by the Ontario Energy Board, and by other regulators in North America, is the stand-alone principle. Applying this principle, the issue is what ought to be a prospective fair return on investment for a utility on a stand-alone basis, and not how a prospective return may compare or compete with other business units of the parent company. Should it be the case that the Ontario gas utilities are unable to attract equity capital by virtue of competition at the parent company level, whether the parent company is foreign or domestic, this would be of great concern to the Board. 124

There was no evidence before the Board to suggest that Canadian utilities in general were experiencing difficulty in raising capital, or doing so at unreasonable terms. Mr. Case mentioned that BC Gas had difficulty raising equity; the equity issue “sat on the shelf” until the dealers were willing to discount it. Dr. Booth countered this point by explaining that the reason that the equity issue sat on the shelf was due to the fact that there was a bidding war amongst investment dealers due to a shortage of such deals at that time. The winning dealer paid a premium for the equity issue in order to secure the underwriting fees. Dr. Booth suggested that this example was in fact a demonstration of how easily a utility could raise capital. 125

Mr. Case pointed to the recent sale of a Canadian pipeline utility by Aquila Inc. as an example of an investor unwilling to invest in Canada. However, the evidence revealed that Aquila was able to sell its pipeline utility to Fortis Inc. at a considerable premium, which would suggest that there are investors willing to invest in Canadian utilities. There was no evidence that Aquila Inc. sold its utility because of concern of the ROE earned by that utility. In fact, the evidence reveals that utility ownership transfers in recent history have taken place at above book value. While there may be many reasons that a company may be willing to pay more than book value for utility assets, there was no evidence to suggest that investors are deterred from investing in Canadian utilities because of inadequate prospective returns. 126

We found no evidence of the Applicants being in financial hardship as a result of the authorized ROE. The Applicants confirmed that they continue to be responsible for raising their own debt capital. There was no evidence, for example, that the allowed ROE has resulted in inadequate financial ratios to preclude raising debt capital on reasonable terms. Similarly, there was no evidence before the Board to suggest that credit ratings of the Applicants were deteriorating. The evidence is that the Applicants enjoy favourable credit ratings. In fact, Union’s credit rating is more favourable than its parent company. 127

Mr. Case made references to changes in the business risk faced by the Applicants, but that issue was not before the Board. The Applicants made their request for a change in ROE based on the capital markets and not on any financial or business risk that they were facing. Ms. McShane confirmed in responding to questions that business and other risks covered by the equity component of capital structure were not matters at issue in this hearing. The Applicants did not dispute this testimony. 128

Having found no evidence of returns being inadequate so as to jeopardize the financial and operational aspects of Enbridge and Union, the issue then is whether the rate of return resulting from the equity risk premium test under the current ROE Guidelines is appropriate. 129

Three tests, and their variants, were employed or critiqued by the experts. All three witnesses had varying views with respect to the appropriateness of relying on the ERP test, the DCF test and the CE test. This was a large contributor to the differences between their recommendations. The other large contributor to the difference was the results arrived at by employing the same tests. The evidence of Ms. McShane, Dr. Booth and Dr. Cannon makes it clear that a great deal of judgment is involved in determining what is an appropriate ROE for a utility. Those three witnesses, along with Mr. Case, were looking at the same capital markets but came up with significantly different recommendations to the Board. However, Dr. Booth and Dr. Cannon also conceded that the current ROE Guidelines were still generally appropriate, despite their recommendations for a lower benchmark ROE. Ms. McShane was more categorical in her view that the ROE Guidelines were no longer producing a fair ROE and that a new benchmark ROE and adjustment formula were needed. 130

On the basis of the evidence adduced in this proceeding, we find that the reservations the Board expressed in the compendium to the current ROE Guidelines about the CE and DCF approaches and the Board's decision not to employ these tests remain valid. With respect to the CE test, we continue to be concerned with the problems associated with the assembling of an acceptable list of comparable companies against which to assess the regulated utility, as well as the selection of a suitable time period from which to draw historical evidence. We note that the subjectivity involved in the selection of an appropriate sample of comparators and the selection of the time period were the primary factors in arriving at an ROE difference of 300 basis points between Ms. McShane and Dr. Cannon. We also reiterate our concern with this test's heavy reliance on past performance as an indicator of future performance. 131

With respect to the DCF test, we note the sensitivity of the results to assumptions, including growth estimates. We note that as a result of different assumptions, Ms. McShane's ROE result from the DCF test is over 200 basis points higher than the results obtained by Dr. Booth and Dr. Cannon. Further, in the context of the specific applications before us, we remain uncomfortable with the results of the DCF test given that the shares of the Applicants are no longer traded on the open market. 132

As a result of the above, we reiterate the Board's conclusions reached when it developed the existing ROE Guidelines that the results from the CE and DCF tests should be given little or no weight for purposes of these applications. 133

We do not accept the suggestions by certain parties to use the approach of averaging the recommendations or to embark on tests that do not have theoretical foundation. Therefore for the purposes of this proceeding we will rely primarily on the results of the ERP test. Other than Mr. Case, all expert witnesses used this test. 134

There are four basic components to this test: a determination of the risk-free rate; a determination of the equity risk premium for the market as a whole; an adjustment (beta) to reflect the lower risk of utilities; and an allowance for financial flexibility or "cushion". Supplemental analysis to the basic ERP test was performed by Ms. McShane and Drs. Booth and Berkowitz. 135

No party has disputed the use of the long-term Government of Canada bond yield as the basis of the risk free rate, or the basis for its forecast as contained in the current ROE guidelines other than the 136 suggestion to fix the spread between the 10 and 30 year bond yields. Also, there was no dispute about the 50 basis points cushion. The disputes are around the determination of the market risk premium and the risk adjustment to reflect the lower risk for utilities.

Ms. McShane calculates a market risk premium of between 600 and 650 basis points. Dr. Booth calculates the premium at about 450 basis points and Dr. Cannon at about 350 basis points. The recommendations of a benchmark return under the basic ERP test of about 400 basis points for Ms. McShane, about 200 basis points for Dr. Booth, and about 160 basis points for Dr. Cannon reflect their choice of a relative risk adjustment of 0.60-0.65, 0.45-0.55, and 0.45, respectively. Adding the 50 basis points of cushion, the recommended benchmark equity risk premium under the basic test for Ms. McShane is 450 basis points, for Dr. Booth 250 basis, and for Dr. Cannon 210 basis points. 137

On the basis of the record adduced in this proceeding, we are of the view that Dr. Cannon’s result is too low and Ms. McShane’s too high. We find that the record reasonably supports a risk premium for the market as a whole between 500 and 550 basis points. We note from the evidence that the Alberta Energy and Utilities Board which recently reviewed similar data concluded that the market premium is 525 basis points. This is the mid-point of our 500 to 550 range. Using this mid-point figure, and without any modifications to Ms. McShane’s recommended risk adjustment, one would obtain an overall equity risk premium of about 375 basis points, inclusive of the 50 basis points cushion. These equity risk premiums compare with 371 basis points for Enbridge and 386 basis points for Union under the current ROE Guidelines. Ms. McShane’s recommended risk adjustment is higher than the other experts. A lower risk adjustment than that recommended by Ms. McShane would result in the equity risk premium under the current formula being favourable to the Applicants. 138

Ms. McShane used two other tests under the risk premium method, both utilizing utility data only. The first was the DCF based equity risk premium test, which produced an equity risk premium of 460 to 470 basis points. For the reasons outlined in the discussion of the DCF approach above, and our observation that the results indicate a much higher equity risk premium than the basic test produces, we place little or no weight on these results. 139

The second is a historic test, using data from both Canadian and American utilities. This test produced an equity risk premium of 475 to 500 basis points. We similarly place little or no weight on these results. We are not comfortable with the circularity that is inherent using regulated utility data, and the inclusion of American utilities which may bias the results without a thorough understanding of the justification for the higher returns of these utilities. 140

We conclude that not only does the equity risk premium formula approach not lead to perverse results, but that the results it currently provides continue to represent fair and reasonable returns. If we had to set a new benchmark rate of return based on the ERP evidence in this proceeding, this rate would not be materially different from that produced by applying the current formula. 141

Therefore, with respect to the first and primary issue of whether a new benchmark ROE should be established for EGDI and Union, we find that the current ROE Guidelines methodology continues to produce appropriate prospective results. We have not found any demonstrated need to set a new benchmark ROE. 142

Given this finding, the second issue, the Applicants' request for the annual ROE adjustment to be decreased to 0.50 from 0.75 of the change in the forecast yield for long-term Government of Canada bonds, is moot. 143

As for the third issue, the suggestion that the factor representing the yield spread between the 10 and 30 Government of Canada bonds be fixed rather than being calculated annually, the Board does not consider this to be of sufficient consequence, by itself, to justify a change to the existing guidelines. 144

Accordingly, based on the foregoing findings, the Board orders that the applications are dismissed. 145

In making this determination, the Board also considered the proposal put forward by Pollution Probe to increase ROE as an incentive to promote cost effective energy conservation and efficiency. The Board notes that the Applicants currently have demand side management programs in place that have already been ruled upon. This proceeding is focussed on whether conditions in the capital markets warrant a change to the Board's formula based approach to setting the ROE for the Applicants. The Board also notes that Pollution Probe and the Applicants are participating in a broad Board initiative that is examining energy conservation and efficiency. 146

The Board will issue a separate decision on cost awards. 147

DATED at Toronto January 16, 2004 148

On behalf of the Hearing Panel

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Paul Vlahos
Presiding Member

Natural Resource Gas Ltd. 2007 Rates, OEB Decision with Reasons
EB-2005-0544

Ontario Energy Board

Commission de l'Énergie de l'Ontario

EB-2005-0544

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an Application by Natural Resource Gas Limited, pursuant to section 36 (1) of the *Ontario Energy Board Act, 1998,* for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission, and storage of gas as of October 1, 2006;

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Cathy Spoel
Member

DECISION WITH REASONS

September 20, 2006

BACKGROUND

Natural Resource Gas Limited ("NRG" or the "Applicant"), filed an application dated March 30, 2006 with the Ontario Energy Board under section 36 of the *Ontario Energy Board Act*, *1998,* S.O. c.15, for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas for the 2007 fiscal year, commencing October 1, 2006.

NRG is a privately owned utility that sells and distributes natural gas within Southern Ontario. The utility supplies natural gas to Aylmer and surrounding areas to approximately 6,500 customers with its service territory stretching from south of the 401 to the shores of Lake Erie, from Port Bruce to Clear Creek. A color coded map showing NRG's franchise area appears in Schedule A of this decision.

The Board issued a Notice of Application, dated April 13, 2006. Only Union Gas Limited ("Union") and Integrated Grain Processors Co-operative (IGPC) intervened. On May 26, 2006, the Board issued Procedural Order No. 1, establishing the procedural schedule for all events up to and including the oral hearing, which was scheduled to commence on July 24, 2006. The Board also ordered a Public Forum to be held in Aylmer on July 18, 2006, to provide NRG ratepayers an opportunity to voice their concerns, seek information, comment or ask questions related to services provided by NRG. The Company was required to attend this event and respond to questions posed by ratepayers. A Draft Issues List was attached to the Procedural Order.

NRG in this application forecasts a revenue deficiency of $135,879 for the 2007 fiscal year. This will result in an annual increase of approximately $4 or one percent to a typical residential customer's annual distribution charge. A typical Commercial customer will see no change while a Rate 1 Industrial customer will see an annual increase of $380 or 11 percent. A typical Rate 2 seasonal customer will see an increase of $504 or 22 percent to their annual distribution charge.

For reasons which follow, the Board grants the requested relief in part. The adjustments to the requested costs are summarized in Schedule B.

THE PUBLIC FORUM

A Public Forum to allow NRG ratepayers to voice their concerns was held in Aylmer on July 18, 2006. NRG participated and was represented by Mr. Mark Bristoll, the Chairman of NRG. The Mayor of Aylmer participated and expressed his appreciation to the Board for holding the hearing within the local community. He did not consider NRG's requested rate increase inappropriate but was concerned about NRG's ability to serve large industrial customers.

Mr. Bristoll indicated that NRG had received a request for significant new industrial load by a proposed ethanol plant. The Mayor wanted NRG to explore the possibility of building a larger pipe than that required to serve the ethanol plant so as to create additional capacity for future customers.

The proposed ethanol plant in the town of Aylmer is an initiative of a 650-member co-operative of southern Ontario corn producers. The $90 million plant will have a production capacity of 150 million litres of ethanol per year and will employ 35 people. The plant is estimated to consume 220 gigajoules of natural gas an hour and could add 50 to 60 million cubic meters to NRG's throughput volume. This would triple NRG's current throughput.

The panel asked NRG to comment on the status of the proposed ethanol plant. NRG indicated that IGPC, the owner of the ethanol plant was in the process of completing environmental assessments and that NRG expects to make a "Leave to Construct" application in the near future. The Mayor expressed concern that construction may not proceed in time to meet the requirements of IGPC. The mayor indicated that the financing of the project was dependent on the availability of required quantities of natural gas to the proposed plant in a timely manner. NRG promised full co-operation and stated that it is a community-based utility dedicated to its growth. Mr. Bristoll continued that NRG would be applying to the Board for the necessary "Leave to Construct" once negotiations with IGPC were completed.

Other issues brought forward by local residents included the difference in rates between Union and NRG, delays in switching to gas marketers and safety issues with respect to installing water heaters.

Some residents complained that NRG's rates were higher than Union's and provided recent bills to demonstrate their point. NRG responded that its average consumption per customer is considerably less than Union's. This was true across the different categories of customers and this resulted in higher operating costs per customer. In addition, NRG noted that its system was newer than Union's and therefore the capital cost for each cubic meter of gas was higher.

One customer expressed her frustration over the fact that her account has still not been moved to a gas marketer. The Company agreed that they have been slow and promised to switch all contracts within 60 days. NRG also provided a list of direct marketers that customers could switch to if they wish.

A safety concern was also brought to the attention of the Board by a customer of NRG. It was related to installation of rental hot water tanks and the customer claimed that NRG allowed self or private installation of hot water tanks. The Company disputed this claim and promised to investigate this particular incident that the customer brought to their attention.

NRG responded to customer concerns about difference in rates between Union and NRG at the oral hearing in Toronto and provided a detailed explanation. NRG's analysis indicated that its cost of providing gas to a residential customer is approximately 20% higher than a customer in Union's southern operations area and 8% higher than a customer in Union's eastern operations area. With respect to NRG's seasonal customers such as tobacco curing customers, the cost is 17% higher than for a similar Union customer.

The Company provided a number of reasons for the difference as outlined below:

- The volumes consumed by an average NRG customer are considerably less than the volumes consumed by an average Union customer. This is true for all classes of customers and essentially makes the NRG system a more costly system to operate.

- NRG has a higher return on equity as compared to Union.
- Union has embedded debt costs of 7.68% in its rates as compared to NRG's total debt cost of 8.45%.
- NRG has a relatively new rate base as compared to Union. This means that its meters, regulators and mains have not depreciated to the same extent as Union's. In other words, NRG is carrying a higher net book value in its rate base.
- NRG's franchise area is essentially rural with no urban centres while Union has large urban centres in its Southern Operations Zone including Hamilton, London and Windsor. This means that NRG has to put more pipes in the ground to get to the same number of customers. This is one of the reasons why Union's other operating areas that are sparsely populated reveal smaller differences in rates when compared to NRG.

Board Findings

The Board recognises and appreciates the concerns raised at the Public Forum by local residents and customers of NRG.

With respect to differences in rates between Union and NRG which was raised at the town hall meeting, the Board instructed NRG to provide an analysis. That analysis[1] explains the differences to the satisfaction of the Board. There are significant differences in operating costs which flow directly from the nature of the territory in which the two companies operate. Essentially NRG enjoys smaller economies of scale than Union. NRG also has newer plant and therefore higher level of capital costs including a higher level of equity and debt.

The Board is concerned about customer complaints that NRG delays moving customers from system gas to direct purchase. The Company has provided assurances to the Board that they are committed to completing the process within 60 days. The Board

[1] See transcript EB-2005-0544 volume 2, pages 103-108

urges any customers who experience difficulty switching their accounts to direct purchase to contact the Consumer Relations Centre of the Ontario Energy Board.

With respect to the new ethanol plant, the Board recognises that this is a major opportunity for both NRG and the town of Aylmer. The Board urges NRG to co-operate with the town and IGPC to the maximum extent possible, in order to ensure that negotiations proceed in an efficient and timely manner. The Board orders NRG to provide a monthly update to the Board on the status of its pending “Leave to Construct” application with respect to the proposed ethanol plant.

The Board further directs NRG to consider the economic feasibility of adding a larger pipeline than that required to accommodate volumes associated with the proposed ethanol plant. The mayor has indicated that this will help attract additional industries and mitigate the local impacts caused by falling tobacco production and the closing of the Imperial Tobacco plant in Aylmer. NRG should look into the possibility of adding additional capacity as long as it does not cause undue burden on existing rate classes or significant cost overruns for NRG and IGPC. Such a study must be filed with the “Leave to Construct” application.

RATE BASE

NRG's updated evidence indicates that its rate base will amount to $9,693,286 in 2007. This is $234,154 more than 2006 forecast and $421,792 more than the previous Board Approved level for the 2005 Test Year. The increase is the result of a $204,084 increase in capital expenditures and an increase of $30,070 in the working capital allowance.

NRG's forecast for capital expenditures is estimated to be $965,207 in 2006 and $867,657 in 2007. NRG is forecasting 44 fewer Rate 2 seasonal customers in 2006 and a further reduction of 27 customers in 2007. This is the result of a recent announcement of a 35% reduction in tobacco quota volumes by the Ontario Flue-Cured Tobacco Growers' Marketing Board[2]. NRG has correspondingly cancelled all capital projects related to Rate 2 customers. This translates to four projects in 2006 and two projects in 2007.

During cross-examination Board staff attempted to determine whether the excess capacity generated from the loss of Rate 2 customers could be used to offset NRG's proposed reinforcement project identified as the Nova Scotia Line. The concern arose from the fact that the benefit/cost ratio of this project is less than one.

The Company indicated that although the loss of Rate 2 volumes may result in some overcapacity, it is not in the appropriate area within NRG's franchise for it to be used for system reinforcement. Although the Nova Scotia Line has a benefit/cost ratio of less than one, NRG indicated that it will not be collecting aid from any customers as it was not possible to identify the customers at this point in time.

With respect to a justification for this project, the Company reiterated its explanation provided in Information Request (IR) No. 6 that the Nova Scotia Line will provide a second feed to the villages of Copenhagen and Port Bruce, as indicated in the colour coded map in Schedule A. In other words, if there was a supply disruption affecting one

[2] The Ontario Flue-Cured Tobacco Growers Marketing Board is a provincial marketing board that operates under the authority of the Farm Products Marketing Act, and the supervision of the Farm Products Marketing Commission. The Board's mandate is the control the production and marketing of all flue-cured tobaccos grown in the province of Ontario. It represents approximately 800 tobacco families plus approximately 150 sharegrowers. For more information, visit www.ontarioflue-cured.com

of the pipelines, the second line could take over providing reinforcement and security of supply. The Company also believes there is a potential to add 48 new residential customers as a result of this expansion with a further possibility of adding one commercial and two industrial customers beyond five years. However, the company indicated that it had not included projections beyond the five-year period in the economic analysis submitted in this application.

Another issue raised by Board staff was related to main additions projects that have been completed to-date in 2006. With less than three months remaining in NRG's 2006 fiscal year-end (September 30, 2006), only $34,358 out of a total of $162,882 has been spent to-date. The Company's testimony indicated that the completion of these projects required 970 man hours. Similarly, main additions for 2007 are estimated to be $232,585 and Board staff's position was that the forecast is overly optimistic. Despite cancellation of some main additions projects, the Company expressed confidence in completing the rest of them. The Company explained that capital expenditures were not added to rate base until the line went into service.

Board staff was also concerned about the substantial rise in the cost of meters for 2006. The Company indicated that a majority of the cost comprised the purchase of a Supervisory Control and Data Acquisition System (SCADA). This system would allow NRG to control the pressure from a central location as opposed to manually adjusting the meters. The balance of the costs was attributed to a new electronic metering system that would allow NRG to read meters remotely. The cost also included a new radio network capable of picking up the electronic signals. The company expected to connect 12 large customers to this new electronic metering system.

Board staff requested the company to clarify why the cost of meters and regulators did not fall in 2006 and 2007 given that a number of main additions projects had been cancelled as indicated in the updated evidence. The company responded in an undertaking that its original estimate for meters and regulators did not include requirements for tobacco loads because it had some meters in its inventory and furthermore it expected that some tobacco customers would terminate service and this would free up meters and regulators that could be re-used.

There was considerable debate on the cost of replacing the company's vehicle fleet. Board staff questioned the justification for replacing a cargo van that is expected to have only 100,000 km on it by the end of fiscal 2007. The targeted replacement cost of all five vehicles during the 2007 test year is $188,000. The Company argued in response that while the mileage on this particular van was relatively low, it was subject to more abuse than other vehicles.

Board Findings

NRG in this application has requested that the Board allow capital expenditures totalling $867,657. These are down from the levels experienced in the previous year. Given the significant reduction in tobacco quotas in the NRG service territory, the Board finds these costs to be reasonable and acceptable.

With respect to the cost of replacing the vehicle fleet, the Board approves the costs with the exception of the one van (2005 Chevrolet Cargo Van). Accordingly, the Board approves a cost of $150,000 ($188,000 - $38,000) for this purpose. The Board does note the subjective nature of NRG's vehicle replacement criteria and the absence of a formal policy in this respect. The Board accordingly directs NRG to develop a written policy for vehicle acquisition, disposition and replacement prior to the next rate case application.

OPERATING REVENUE

NRG's total operating revenue is divided into two components – gas distribution and transportation revenue, and other operating revenue (net.). This latter category is made up of the rental equipment program, contract work program, service work program, merchandise sales, direct purchase fees, delayed payment charges and transfer/connect charges.

NRG's updated evidence indicates that its operating revenue will amount to $4,570,085 in 2007. This is $107,859 more than 2006 forecast and $105,488 more than the previous Board Approved level for the 2005 Test Year. The increase in operating revenue is associated with the forecast of 325 additional customers (net) in 2006 and 367 customers (net) in 2007[3].

Gas distribution and transportation revenue totals $3,889,059 or 85.1% of total revenues. Other operating revenues (net) accounts for the remaining revenue of $681,026. Total customers forecasted for the fiscal 2007 test year is 6,872 with an associated throughput volume of 23,566,141 cubic meters.

NRG's forecast for operating revenue in 2006 and 2007 are lower than the original pre-filed evidence and is attributed to a forecasted loss of Rate 2 tobacco curing customers. NRG is forecasting 44 fewer Rate 2 seasonal customers in 2006 and a further reduction of 27 customers in 2007. This is the result of a recent announcement of a 35% reduction in tobacco quota volumes by the Ontario Flue-Cured Tobacco Growers' Marketing Board.

The original pre-filed evidence did not include volumes related to Imperial Tobacco because NRG forecasted the loss of that customer in fiscal 2007. However, a response to an Information Request[4] revealed that the customer could be in operation until mid to late calendar 2007. NRG's updated evidence indicated a volume forecast of 3,391,247 cubic meters for this customer through to the end of June 2007.

[3] Exhibit C1/Tab1/Schedule 4 Updated Evidence
[4] Board staff IR Number 8

Board staff questioned NRG’s residential additions forecast for fiscal 2006 and argued that NRG’s prediction of 353 new residential customers in 2006 seemed to be very optimistic.

As of June 2006, NRG added 200 new residential customers. Data from the last ten years for additions by month suggests that NRG may end up adding another 25 to 30 customers by the end of the 2006 fiscal year (September 30, 2006). Board staff added that in order to meet its forecast figure of 353, NRG required the addition of approximately two customers per day till the end of September 2006.

NRG insisted that the forecast was appropriate and with the help of an aggressive advertising and marketing campaign, they were confident that the forecasted figure of 353 new residential customers was realistic. Given that NRG’s current penetration rate of 70% on its distribution system is relatively low compared to other utilities, NRG believes there are significant opportunities to grow volumes and customers.

Board staff also questioned NRG’s forecast that indicated a loss of 44 Rate 2 customers in 2006 as well as the methodology used to determine that forecast. NRG indicated that it drove by every farm that it had an account with to determine whether they had tobacco in their fields. The resulting number was validated against a 35% reduction in customers corresponding to the 35% reduction in quota. The numbers from the two methodologies were fairly close and the lower number of 77 was used in the application. For 2007, the 2006 number was simply reduced by 35% yielding a total of 50 customers.

With regard to the proposed ethanol plant, Board Staff sought clarification on the impact that the ethanol plant would have on NRG’s throughput and distribution system. NRG indicated that its throughput volume would triple due to the significant demand of natural gas the ethanol plant would require. NRG’s forecasted load for 2007 is 23.5 million cubic metres and this would increase to 70-80 million cubic metres with the inclusion of the ethanol plant. The existing system in not capable of handling this load for two reasons: (i) the volumes are significantly larger and require a separate feed from the Union Gas system, and (ii) the plant requires a higher delivery pressure than NRG can currently provide.

The panel questioned why NRG was cautious about gaining the ethanol plant as a customer. NRG indicated that the project requires a significant outlay of capital of approximately five million dollars. In addition, the costs that NRG pays to Union Gas under the M9 delivery contract would essentially double as the peak demand would double with the ethanol plant. Moreover, addition of the pipeline would increase NRG's rate base to more than ten million dollars, making NRG ineligible for the capital tax exemption. In addition, property taxes on 31 kilometres of a high-value pipeline would be substantial.

The Board also questioned NRG on how it would be impacted if the tobacco industry disappeared in its entirety in its service territory. NRG indicated that this would lead to $200,000 in costs that would need to be allocated to other rate classes. NRG did not have any contingency plans in place to address this possibility.

In the closing statement, Board staff reiterated their position that the residential customer addition forecast for 2006 and 2007 was too ambitious and this was also reflected in the volume forecast. NRG's reply argument stressed the aggressive advertising and marketing campaign and considered this program crucial to the company's efforts to mitigate the revenue loss from tobacco customers.

Board Findings

The Board accepts NRG's 2007 forecasted total throughput volume and operating revenue of 23,566,141 cubic meters and $4,570,085, respectively.

The Board notes the optimistic forecast with respect to residential customer additions in 2006 and 2007, but accepts NRG's explanation that an aggressive advertising and marketing program will help meet forecasts. The Board also accepts NRG's 2007 forecasted customer numbers of 6,872.

The Board is concerned about the significant reduction in the 2006 tobacco quota and its impact on NRG's tobacco curing customers. NRG has forecasted a further drop of 35% in the tobacco quota resulting in a loss of 27 customers in 2007. The Board acknowledges that the loss of 71 customers in 2006 and 2007 will lead to a significant erosion of this rate class. The Board is also concerned about the lack of data for the 2007 test year with respect to the tobacco quota. Recognising that there is a further risk to this rate class, the Board accepts NRG's forecasted Rate 2 volumes and numbers, but at the same time directs NRG to consider developing a contingency plan to address possible reduction in volumes as well as a potential loss of the entire rate class.

COST OF SERVICE

NRG's cost of service forecast for the 2007 test year totals $3,770,275. Operation and Maintenance costs total $2,149,572 or approximately 57.0% of the total cost of service. Depreciation and amortization totals $731,597 or 19.4% of the cost of service. Property, capital and income taxes account for $440,669 or 11.7% of the cost of service. Gas transportation costs account for the remaining $448,437 or 11.9% of the cost of service.

Net wages and benefits account for approximately 45% of the total Operating and Maintenance costs. A list of some of the important cost items together with a comparison to the 2005 level of costs appears below:

O & M Costs	2005[5]	2007[6]
Wages	801,900	911,623
Employee Benefits	120,800	132,997
Insurance	265,000	273,911
Advertising	22,000	74,861
Telephone	41,500	33,758
Repair & Maintenance	159,600	149,316
Automotive	54,500	99,551
Regulatory	108,500	193,700

Board staff examined a number of areas including unaccounted for gas, gas transportation costs, automotive expenses, regulatory costs, bad debt expenses, advertising costs and the cost of gas.

NRG has requested modification of the methodology used to account for unaccounted for gas. NRG's methodology uses a 3-2-1 weighting of the unaccounted for gas for the last three years. This is a Board-approved methodology and similar to the one used by Union Gas. The Company is seeking approval to use the same methodology but

5 Board Approved amounts (RP-2004-0167)
6 Updated Evidence, Exhibit D1/Tab3/Schedule2/Pg.1

subjecting it to a floor of zero percent. The current methodology does not have a floor limit.

Board staff argued that NRG has reported gas gains in two out of the three previous years, namely 2003 and 2005. NRG argued that a majority of the gas gain is due to NRG's fiscal year end being September when tobacco volumes are at their highest. This can result in significant swings in unbilled volumes as a result of a difference in billing cycle versus the calendar month. NRG also confirmed that it is more of a volumetric issue than an accounting one. NRG indicated that there is no adverse impact on customers. Even if the floor was set at a gas gain of 0.2%, the net impact after tax would be a negligible decrease of $223.

Board staff questioned NRG's proposed automotive expenses of $99,551 which included repair and maintenance costs of $18,735. There was no evidence why repair and maintenance costs were increasing when the company proposed to replace five vehicles in 2007. In response to an undertaking, NRG explained that part of the $18,735 includes expenses related to equipping the new vehicles with accessories such as racks and shelving.

NRG's pre-filed evidence indicated regulatory costs of $192,700 of which $131,700 relate to the 2007 cost of service hearing. In response to a Board staff IR, NRG indicated that it intended to file the next rates case in December 2007. This has since been changed to December 2006. Board staff questioned the rationale for this change considering that NRG submitted a report as per Board's direction in RP-2004-0167 supporting a multi-year rate filing. NRG was of the view that the proposed ethanol plant would result in a significant change in its rate base and operations warranting a cost of service application. However, NRG indicated that it did not wish to wait until the end of the year to file, in effect delaying the current application, for the simple reason that there was some uncertainty around the construction of the ethanol plant.

Board staff questioned NRG on the possibility of a rise in collection and bad debt related costs as a result of an expected loss of Rate 2 customers in 2006 and 2007. NRG indicated that it did not foresee a rise in collection related and bad debt expenses.

Board staff specifically focussed on the proposed advertising expenditures of NRG. The cash rebate program forms a major part of NRG's proposed advertising budget and is estimated to cost $198,250 in 2007. NRG planned to amortise the cost over an eight-year period. The program is intended for residential customers who convert an appliance from an alternative fuel to natural gas. These customers would receive a rebate for the natural gas equipment that they purchased or rented as an incentive to convert to natural gas. For example, a person converting to a natural gas furnace would receive a one-time rebate of $450.

During cross-examination, NRG confirmed that although the ancillary business sold furnaces, water heaters and appliances, none of the advertising expenditures were allocated to the non-regulated portion of the business. NRG argued that the goal of the rebate was to increase throughput and the rebate was distributed irrespective of where the customer purchased the gas fired appliance. However, NRG did agree that majority of the sales or rentals were going through them. Board staff maintained that the ancillary business should bear some of the advertising costs as they derive some benefit from the program. It is fair to assume that fewer people would purchase or rent appliances from NRG without the existence of this program.

The forecast of customer additions was also questioned. NRG forecasted the addition of 353 residential customers in 2006. To-date NRG has added approximately 200 customers and based on historical statistics is likely to add another 25 by the end of the fiscal year. Board staff expressed concern about the numbers and the likelihood of NRG adding another 150 customers by the end of September.

Board staff also questioned the rationale for selecting an eight-year amortization period for the cash rebate program. In reply NRG indicated that the eight year period represented the approximate time to recover the rebate amount in rates from the customer. The net benefit of the program was greater than one beyond eight years.

Another program that NRG planned to introduce was the lead pay program. This is an incentive tool for employees to encourage conversion to natural gas. During cross-examination, NRG explained that the $10 lead fee would be paid only if it resulted in the conversion of an appliance. This program is estimated to cost $6,000 in 2007.

Finally, Board staff examined the gas purchases from NRG Corp., a related company. Board staff was concerned that the contract price in 2006 was substantially higher than the forecasted average price for the year. NRG clarified that the contracted price was determined by calculating the one-year forward strip over the last ten business days of September 2005. Board staff presented an Exhibit “Canadian Natural Gas Focus (October 2005)” that showed the NYMEX 12-month forward price in September. This price was significantly different from the one NRG used in its contract. NRG presented its own evidence, a document titled, “The Source Report” from which NRG determined the price. Board staff expressed satisfaction with the source and the methodology to calculate the price so long as the source and the methodology used were consistent going forward.

In final argument Board staff expressed concern with the forecasted customer additions and the rationale for spending almost ten times the amount for marketing and advertising as compared to past periods. The second issue dealt with the allocation of these advertising expenses. Board staff did not agree with the allocation of 100% of advertising expenses to the regulated side of the business when the ancillary business derives additional sales and profits from this program. Citing the example of the water heater grants program that was allocated 100% to the ancillary business, Board staff questioned if the current program was radically different. Board staff recommended allocating some portion of the proposed advertising and marketing expenses to the ancillary portion of the business.

In its reply argument NRG stressed that all ratepayers across all rate classes would benefit from the marketing campaign as a result of additional throughput. Moreover, there are occasions when the ancillary business does not benefit from the rebate programs. Customers were eligible for rebates even if they purchased their equipment elsewhere. In other words, the ancillary business may not derive all the benefits that Board staff claimed. NRG also confirmed the success of their marketing programs to-date and expressed confidence in meeting their targets.

Board Findings

The Board approves NRG's request for setting the floor of 0.0% for the test year. NRG has recorded gas gains in only 4 of the last 24 years and as tobacco volumes fall, further swings in unbilled volumes are likely to decline.

The Board understands the challenges faced by NRG with respect to serving the ethanol plant and the significant impact this potential customer will have on its cost structure and rates. The Board supports NRG's rationale for filing a cost of service application in December. However, NRG needs to recognize the cost consequences of frequent regulatory filings on its small customer base.

The cash rebate program forms a significant portion of NRG's proposed advertising expenditures. The Board is concerned about NRG meeting its target with respect to customer additions and the overall benefit of this program. However, NRG is confident of meeting this target and the Board accepts this assurance.

It is evident that the cash rebate program will provide some benefit to the ancillary business. The ancillary business is making profits and according to testimony of NRG, the percentage of profit is similar to the regulated portion of the business. The Board directs NRG to allocate a portion of the advertising expenditures for programs that involve selling or renting gas appliances, namely the cash rebate program and the lead pay program, between the ancillary and regulated businesses according to revenues. Accordingly, 85% of program costs will be borne by the regulated business and the balance, 15%, by the ancillary business.

The evidence also discloses an inconsistency between the number of appliances that are likely to be sold or rented under the cash rebate program and the lead fee that will be paid to employees for a successful conversion. The evidence indicates that NRG is likely to convert 201 appliances from other fuel sources to natural gas. In addition to paying a cash rebate for each conversion as discussed previously, the company could also be paying sales people a $10 lead fee for every conversion secured through them. The cost estimate for this expense in the application is $6,000 which would suggest 600 leads. The inconsistency stems from the fact that all customers acquired as a result of leads would be made aware of the cash rebates available and therefore would not be able to exceed the numbers projected for the cash rebate program. Accordingly, it seems appropriate to adjust the cost of the lead pay program from $6,000 to $2,010 based on a maximum of 201 conversions. The Board accepts NRG's rationale for amortizing the costs of the cash rebate program over an eight-year period.

The Board accepts NRG's methodology to calculate natural gas prices associated with purchasing gas from the related company. However, the Board directs NRG to seek prior permission should it decide to change either the source from which prices are calculated or the methodology used to determine the contract price.

CAPITAL STRUCTURE AND COST OF CAPITAL

NRG's proposed capital structure and cost of capital for the 2007 Test Year is detailed below:

Capital Structure – Cost of Capital[7]
2007 Test Year

	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)
Long-term debt	6,406,924	66.10%	8.45%	5.58%
Short-Term Debt				
Operating Loan	0	0.00%	6.00%	0.00%
Unfunded Debt	(106,288)	-1.10%	6.00%	-0.07%
Common Equity	3,392,650	35.00%	10.20%	3.57%
Total	9,693,286	100.00%		9.08%

The main differences between the 2005 Test Year Board-approved Capital Structure and Cost of Capital, and NRG's proposal for 2007 are as follows:

- Equity ratio decreases from 50% to 35%
- Return on equity increases from 9.57% to 10.2%
- Long term debt ratio increases from 31.43 to 66.1%
- Long term debt rate increases from 8% to 8.45%
- Short term debt ratio decreases from 17.3% to a 1.1% credit
- Short term debt rate increases from 5.5% to 6%

[7] Exhibit 6, Tab 1, Schedule 1, Updated Evidence

Mr. Bristoll testified as the Company's witness on NRG's proposed capital structure and return on equity. Ms. Kathleen McShane, of Foster Associates Inc., testified as the Company's expert witness. The purpose of Ms. McShane's testimony was to evaluate the reasonableness of NRG's proposed capital structure and to determine the risk premium for the utility. Ms. McShane's analysis and evaluation, Opinion on Capital Structure and Equity Risk Premium for Natural Resource Gas[8] concluded that for the 2007 Test Year, a 35% common equity ratio is reasonable and recommended that a 150 basis point premium be added to the return on equity amount as calculated using the Board's Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities.

During cross examination Board staff explored three issues: (1) the possibility that a range of equity ratios could be appropriate, (2) the factors leading to changes to NRG's equity ratio that the Board considered in previous decisions, and (3) the role risk has in determining capital structure and rate of return.

Ms. McShane agreed that there is a range of acceptable equity ratios. A ratio within the range of 35% to 55% would be reasonable for a specific utility, given the appropriate common equity return for the utility. In the witness's opinion, the Board in previous decisions had approved increases in NRG's deemed equity ratio because the actual ratio had reached 50% and a 50% equity was reasonable for the level of business risk that NRG faced. With regard to the changed circumstances that would prompt a 35% equity ratio, Ms. McShane indicated that the company had re-financed and raised new debt, thereby establishing an actual common equity ratio of approximately 35%; and that 35% is appropriate to use because it is the actual ratio.

Mr Bristoll's rationale for the change was that NRG had been prevented from issuing dividends (due to the Imperial Life Loan covenants) and that, given the low interest rates, the time was right to go to market to re-finance. He indicated that NRG cannot go to market repeatedly and noted that the new structure was good for ratepayers since it reduced NRG's revenue deficiency.

[8] Exhibit E2, Tab 1, Schedule 1

Ms. McShane stated that NRG's risks, and those relative to other gas distributors, had not changed appreciably. The witness confirmed that if there had been a significant increase or decrease in business risk, then that should be reflected in a capital structure or equity return change. With respect to NRG's comparative risk with Enbridge Gas Distribution Inc. (EGDI), the witness concurred with the proposition that if the Board agrees that the business risk of NRG relative to EGDI has declined, then it would lead to a lower risk premium. The witness noted that, if NRG moves to a 35% equity ratio, there is no reason to believe that the overall cost of capital would be any different, assuming no material change in the business risk.

With respect to the proposed 150 basis point risk premium, Ms. McShane indicated that a 150 basis point risk premium was justified. Her conclusions were based on the consideration of three factors: the difference of cost of debt between the utilities, the impact of size on return (Ibbotson Study) and the equity return rate which under a different capital structure would result in an equivalent cost of capital, assuming no change in business risk.

Board staff questioned the witness's assumption that NRG's business and relative risk had not changed since the 1998 Test Year decision in which the Board approved a 50% equity capital structure and a rate of return on equity equivalent to Enbridge Gas Distribution Inc's.

The panel sought clarification regarding the witness's claims that (i) NRG's entire market and not just the agricultural sector, is riskier than Enbridge Gas Distribution Inc.'s, (ii) NRG's residential component is riskier because it is less diversified, more dependent on an agricultural base (iii) NRG doesn't have the diversity of employment that EGDI has, and (iv) the agricultural sector is more risky than industrial markets.

Ms. McShane acknowledged that she had not examined data supporting the conclusion that NRG's residential market is less diversified and also reiterated that her assessment of the market being more risky is based on the total market and not just the residential portion. The witness indicated that she didn't necessarily look at number of customers nor revenue to ascertain relative risk but rather looked at the gross margin attributable to the different customer classes and supported the proposition that the greater the proportion of revenue or gross margin, that comes from residential customers, the less risky the market. The witness did not disagree with the proposition that replacing tobacco load with residential load, and all things being equal, would reduce the overall business risk.

In this regard, the Company filed Exhibit K 2.4[9] which provided comparative customer and market related information for NRG, Union Gas Limited and Enbridge Gas Distribution as set out below.

	NRG	Enbridge	Union[10]
Residential Sector			
Percent of Customers	91	91	90.5
Percent of Volumes	46	37.5	19
Percent of Gross Margin	70	60	59
Commercial Sector			
Percent of Customers	6	8.6	9
Percent of Volumes	14	40	13
Percent of Gross Margin	13	32	26
Industrial Sector			
Percent of Customers	3	0.4	0.5
Percent of Volumes	40	22.5[11]	68[12]
Percent of Gross Margin	17	8	15[13]

Of these three breakdowns by customer class, the gross margin is the most indicative of the utilities' dependence on the industrial class. Note that the Union data are for in-franchise operations only. The industrial gross margin as a percent of the total, inclusive of storage and transportation revenues, is approximately 12%. Note also that the industrial data do not provide any insight into the diversification among industries.

Counsel for IGPC questioned Ms. McShane's reasoning for recommending a 150 basis point premium, despite the fact that in 1995 the Board had approved a 135 basis point premium, when in both cases the equity ratio is 35%, and NRG's risk has declined since that time. Ms. McShane responded that one could not make a direct comparison

[9] EXHIBIT K 2.4:
To Provide Figures for Revenue and Number of Customers for Residential as a Percentage of Total Revenue and Number of Customers for Enbridge Gas Distribution, Union Gas Limited and NRG; To Provide the Percentage of Gross Margin Coming from both Residential and Industrial Customers
[10] Excludes storage and transportation, which accounts for 20% of revenues
[11] Includes wholesale (Gazifere)
[12] Includes large commercial
[13] Includes large commercial

between the two situations and conclude definitively that it represented an increase in risk premium.

Board staff in its closing argument identified two issues for the Board's consideration. The first was whether the equity ratio should be reduced to 35% from its deemed 50%. The second was whether there should be an equity risk premium, and if so, what that premium should be.

Noting Ms. McShane's suggestion that the equity ratio can be between 35% and 55%, Board staff questioned whether deeming an equity ratio at the lower end of the range would impact NRG's ability to raise debt to finance the pipeline for the proposed ethanol plant.

Regarding the 150 basis point risk premium proposed by NRG, Board staff referred to expert witness testimony that small cap companies have greater risk than larger-cap ones and that business risk is related to size and diversity of market. Board staff noted that there is evidence indicating that NRG is similar to Union, on the basis of gross margin by rate class, and that NRG's exposure to the industrial class has declined form 17% to 11%. Board staff suggested that as residential load increases relative to the riskier industrial load, business risk should decline because the margin on residential load is twice that on industrial load.

Board staff also referred to previous decisions which could be of assistance to the Board. In RP-2002-0158[14] Union Gas Limited was granted a 15 basis points premium over EGDI and in EBRO 480[15] NRG was given a 50 basis point premium over Union. Board staff suggested that the appropriate premium for NRG should be around 65 basis points, the sum of 50 and 15.

Counsel for IGPC agreed with Board staff that a risk premium is warranted in the range of 60 to 75 basis points. Mr. Stoll indicated that the recent Bank of Nova Scotia loan and the growth in the number of residential customers suggested a stronger utility for which a

[14] RP-2002-0158, In The Matter of Applications by Union Gas Limited and Enbridge Gas Distribution Inc. For A Review of the Board's Guidelines for Establishing their Respective Return On Equity, Decision and Order, paragraph 45
[15] EBRO 480, NRG Ltd., Decision, Section 6.5.19 and Appendix I, pgs. 5 & 6

150 basis point premium was not warranted. With respect to capital structure, Mr Stoll supported a 35% equity ratio.

NRG addressed two issues in its closing submission: capital structure and return on equity.

The first concerned the new cost of equity calculation proposed by NRG which assumed that NRG's risk had not changed appreciably relative to that of EGDI. Mr King submitted that NRG's relative risk had not changed materially. Although NRG's riskiest customers are forecasted to leave the system, the risk is only reduced if the "leaving" customers are replaced by new customers. Mr King noted that NRG's gross margin from the industrial sector is declining and that, as pointed out by Ms. McShane, Enbridge's and Union's industrial sector is more diversified than NRG's, and consequently less risky.

The second issue raised by NRG was the appropriateness of NRG's proposal to decrease the equity component of its capital structure from 50% to 35%. To the concern raised by IGPC that a low equity ratio will hinder NRG's ability to fund or obtain funding for any capital investments required to attach the new ethanol plant, counsel for NRG pointed to Mr. Bristoll's testimony that the company remains strong, post-refinancing, and that financing particulars would be addressed by the Board when the project plans are firmed-up. On the matter of the dividend pay-out, NRG noted that had it paid a dividend over the past 12 years, it would be in the same position as it is in today in terms of dealing with any funding requirements related to the planned ethanol plant.

Board Findings

NRG in this application requested an equity ratio of 35%. The evidence shows that the actual equity ratio is 41.5%. This is the ratio that results after the Bank of Nova Scotia financing and the payment of $2,038,581 to shareholders.

It is not clear why NRG was proposing 35% equity ratio except that the company's expert witness appeared to believe that was the actual ratio. The Board agrees with the principle that the actual ratio should be used unless the ratio is considered to be unreasonable. In the past, the Board has used a deemed equity ratio for NRG, but that was on the basis that the actual equity ratio was unreasonable. In this case, the Board finds that the actual equity ratio of 42% is reasonable. It does reflect the fact that NRG is a more risky utility than Enbridge Gas Distribution and Union. However, the Board is convinced that the equity financing is a sound third-party financing and there is no basis for assuming that the actual ratio of 42% is unreasonable. Accordingly, the Board sets NRG's common equity ratio to 42% for the 2007 fiscal year.

With respect to the risk premium, NRG requested a 150 basis points equity risk premium over Enbridge Gas Distribution Inc. This Board in the past has allowed Union a 15 basis points risk premium[16] over Enbridge. The Board agrees that risk premiums are appropriate in certain cases. However, the Board does not see why NRG's risk premium should be ten times to what was approved for Union (15 basis points as compared to 150 basis points).

The position of Board staff and IGPC was that there should be some risk premium but that it should be in the range of 60 to 80 basis points.

It is important to note that if anything NRG's risk is declining. The Company's evidence indicates impressive growth figures. These include tripling the number of customers since 1991 and the forecast for 2007 indicates a strong growth in residential load. This is likely to replace in part the risky tobacco load which will reduce the risk that has dominated NRG's business in the past.

It is also significant that the Company has for the first time been able to secure arms length financing for all of its debt. And for the first time NRG has been able to obtain financing from a major financial institution, in this case the Bank of Nova Scotia. The amount of debt is almost twice the level of its previous long-term debt at an interest rate far lower than rates previously paid by NRG. This in itself goes a long way to reducing the risk of NRG as an operating utility.

For the reasons expressed above, the Board is of the view that a risk premium of 50 basis points over Enbridge Gas Distribution Inc. is justified. It should be noted that while

[16] Decision and Order RP-2002-0158, Para 45

the Board has rejected the requested 150 basis points risk premium, it has increased the equity component from 35 to 42 percent which offsets this in part.

FINANCING AND REDEPLOYMENTS COSTS

The Board has asked NRG in previous rate cases to refinance its long-term debt. In RP-2004-0167, the Board indicated that it will address recovery of breakage costs through rates if and when they are incurred. NRG has refinanced its debt and has incurred two types of costs; (1) financing costs with respect to obtaining the new loan from Bank of Nova Scotia and (2) prepayment penalties associated with the retirement of its previous debt instruments.

The financing cost is $47,793 and includes a commitment fee of $20,000, Bank legal fees of $20,000 and another $7,793 in legal fees of NRG. The redeployment costs total $219,116.85 including interest of $5,864.46. The prepayment penalties for the Imperial Life loan and Banco Securities Debenture are $192,970.59 and $20,281.80 respectively. NRG is requesting the recovery of all financing and redeployments costs.

NRG has proposed to recover the financing costs of $47,793 over the term of the new loan, which is over a period of five years, amounting to $9,559 per year. With respect to refinancing costs, NRG proposes to amortize the costs including accumulated interest, over the remaining life of the new loan beginning in the fiscal 2007 test year. The remaining life is forecast to be 53 months as of October 1, 2006.

During cross-examination NRG was asked to explain how the redeployment costs were calculated. The pre-payment penalties on the Imperial Life loan and the Junsen Debenture represents the difference between the July 2009 long-term rate (maturity of the loan) and the rate on the loan net present valued over the remaining period of the loan. This is in contrast to the Bank of Nova Scotia loan which has a three-month interest penalty for pre-payment.

Board staff argued that the Junsen Debenture was held by a related party and in a previous rate case the Board disallowed recovery of the Junsen penalty stating:

> "However, the Board has not factored the pre-payment penalties related to the Junsen Debenture into its determinations. The Board does not believe that NRG would have agreed to the insertion of such

> a clause into the debenture agreement in 1998 if it had been negotiating with an arms-length third party."[17]

NRG's reply was that it is not unusual for the lender to have some kind of a pre-payment penalty clause in order to protect their interest and even the Imperial Life loan and the Nova Scotia loan have pre-payment penalties.

Board staff further argued that the Board made those comments within the context of an impending refinancing and the acceptance of a penalty clause in those circumstances was imprudent and not the concept of a penalty clause in general. NRG's testimony indicated that since the financing did not occur at that time, the Board had not disallowed the penalty from being considered in subsequent cases. NRG considered these costs to be prudent and a common practise in lending arrangements.

In reply to an undertaking NRG provided three-month pre-payment penalties for all three loans, Imperial Life, Junsen Debenture and Bank of Nova Socita. The panel asked for this information in order to understand how onerous the Banco Debenture penalty was as compared to Imperial Life and Bank of Nova Scotia. The three-month penalty for Imperial Life works out to $41,446.57, Banco Debenture $6,263.14 and for Bank of Nova Scotia it is $121,867.29. However, NRG did add a caveat that all loans were at different points in time representing different financing needs and different abilities to borrow money.

The second issue that Board staff focused on was the one percent premium on interest rates that the Board approved in 2004 rates. This one percent premium works out to $31,698 inclusive of the impact of income taxes.

Board staff argued that it was evident in the Board Decision RP-2002-0147 that the one percent premium awarded to NRG on its debt was to cover some of the financing and transaction costs related to the refinancing of its debt. NRG's position was that it is not clear what the Board meant and the 9% represented the deemed rate for that year.

[17] RP-2002-0147/EB-2002-0446, Para 84

The last issue in this area dealt with the amortization period that NRG proposed for accounting refinancing costs. Board staff questioned NRG's motive for not charging a portion of the refinancing costs in 2006 when it was evident that lower interest rates on the Bank of Nova Scotia loan will provide some benefit to the company in 2006. NRG quoted the Board's previous decision that states that NRG should come before the Board for recovery of breakage costs in rates. NRG indicated that its application reflects the Board's policy of not implementing retroactive rate increases.

Board staff argued that NRG had benefited in the amount of $40,000 by refinancing at a lower rate of 7.52% as compared to paying a higher interest rate that was attached to their previous loans. Moreover, a portion of the proceeds from the current loan was being paid out as a special dividend to the shareholder and Board staff suggested that the shareholder should be responsible for a part of the breakage fee. NRG did not deny the benefit but did point out that if they wanted they could have refinanced in September or October, a period closer to NRG's fiscal year end. Moreover, the shareholder had not received any dividend since 1994 and if the financing mechanisms had allowed distribution of dividends, the shareholder would have received dividends during the loan period and this could have worked out to be the same as the one-time special dividend.

In closing arguments, Board staff recommended that the Board not allow the recovery of penalty costs associated with the Junsen Debentures, the 1% premium ($31,698) that the Company has already collected in rates in 2004 and an amount of $6,960 representing the interest rate differential between the deemed rate of 8.0% and the actual rate of 7.52% that the company would be paying in the last six months of 2006.

The Junsen Debenture was not an arms-length transaction and the additional penalty clause was entered into after the company was aware that the Board wanted them to refinance. And further there was no evidence whether the company even used the additional credit facility that was the prime motivator to enter into this agreement. Referring to the one percent premium, Board staff reiterated their position that had the Board not intended to give them monies to cover refinancing and transaction costs, they would have given 8% versus the 9% approved in RP-2002-0147. The fact that the refinancing was not undertaken is irrelevant to the fact that over $31,000 had been collected from ratepayers.

In its reply argument, NRG pointed to the Board Decision RP-2004-0167 that instructed the Company to bring forward all refinancing costs when incurred and that is exactly what NRG had done. Penalties related to the Junsen Debenture form part of the refinancing costs. NRG argued that including a breakage fee clause is common practice in lending agreements so as to protect lenders of fixed-rate loans from borrowers disappearing when rates are lowered. Referring to the one-percent premium, NRG reiterated its earlier position that it did not agree with the position of Board staff.

Board Findings

The Board appreciates NRG's efforts to refinance its debt. However, the Board notes that the Banco Securities Debenture was not a third party transaction and the prepayment penalty constitutes a significant portion of the total loan amount (4.28%). However, the Board is aware that most financial agreements do carry a prepayment penalty clause and a 3-month interest penalty is fairly common. The Board therefore approves a 3-month interest penalty for the Banco Securities Debenture. This amounts to $6,263.14 as indicated in Undertaking J1.6.

The Board does not agree with Staff's argument that the one percent premium awarded to NRG in Decision RP-2002-0147 was to recover refinancing and transaction costs. The decision does not explicitly state that the 9% deemed rate on the cost of debt includes a one percent premium to recover future financing costs irrespective of when NRG refinances its debt.

NRG proposes to amortize refinancing costs including interest over a period of 53 months starting October 1, 2006. NRG's intent is to align the amortization period with the term of the loan. The loan is for a period of five years or 60 months beginning in March 2006. NRG has applied for rates effective October 1, 2006. The Board believes that customers should get the same 60-month period and should not be asked to pay more every month in rates because NRG refinanced earlier in 2006. The Board orders NRG to amortise the refinancing costs over a 60-month period and not 53 months as proposed in the evidence.

The Board does not agree with the position of staff that NRG should be allowed to recover the actual cost of 7.52% for the second half of 2006 as opposed to the deemed rate of 8.0% because that would amount to retroactive rate making. A rate of 8.0% was approved in the previous decision and the company is allowed to recover that amount for the entire year.

The following refinancing costs are accordingly approved for recovery:

• Prepayment penalties for the Imperial Life Loan	-	$192,970.59
• Junsen Debenture	-	$ 6,263.14
• Interest costs	-	$ 5,478.93
Total refinancing costs approved	-	$204,712.66

The Board orders that the above costs be amortized over a 60-month period.

The Board approves a rate of 6.00% for short-term debt. This issue was not contested in the proceeding.

COST ALLOCATION

NRG proposed to modify the previously Board approved cost allocation study to reflect the 2007 revenue requirement, to incorporate the updated information and to reflect a number of changes to the functionalization, classification and allocation of costs.

The updates and changes to the cost allocation study fall into three categories. The first category consists of updates to the calculation of the coincident and non-coincident peak allocators and the calculation of the zero intercept study to reflect the most recent information available. The second category consists of changes to the functionalization, classification and allocation factors that are the result of updated information or circumstances. The third category of changes relate to the fully allocated cost study.

NRG did not propose a change to the methodology used in the Fully Allocated Costing Study that was approved in RP-2002-0147.

Board staff focused on the proposed advertising expenditures associated with the cash rebate and lead pay program, specifically in the context of the allocation of the costs of these programs. During cross-examination, NRG confirmed that while majority of the sales and rentals were through its ancillary business, none of the advertising expenditures were allocated to the non-regulated portion of the business.

Board Findings

The Board approves NRG's proposed updates to its previously approved cost allocation model.

With respect to the allocation of costs of the cash rebate program and the lead pay program, the Board notes that based on NRG's testimony the ancillary business is making a profit and the percentage of profit is similar to that of the regulated portion of the business.

The Board notes that since NRG's ancillary business derives some benefit from the sale and rental of natural gas equipment designed to increase the Company's throughput volumes, the Board directs NRG to allocate a portion of the advertising expenditures for programs that involve selling or renting gas applications, between the ancillary and regulated businesses according to revenues.

RATE DESIGN

In order to increase the fixed cost recovery through the monthly fixed charge, NRG proposed to increase the monthly fixed charge from $9.50 per month for Rate 1 customers to $11.50 per month and to decrease the first block delivery charge and increase the second block delivery charge. This proposal will result in an increase of approximately $4 (1%) to a typical residential customer's annual distribution charge. A typical Commercial customer will see no change while a Rate 1 Industrial customer will see an increase of $380 (11%) to the annual distribution charge.

NRG proposed a $2 increase to the monthly fixed charge for Rate 2 customers that would increase the fixed charge from $10.75 to $12.75 per month. In addition, a decrease to the delivery charge in the first block in the April through October period was proposed as was an increase to the delivery charge in the second and third blocks in the April through October period. No changes were proposed to delivery charges in the November through March period. A typical Rate 2 seasonal customer will see an increase of $504 (22%) to their annual distribution charge as a result of the proposed changes.

For the Rate 3 - Large Volume Contract Rate, NRG proposed to increase both the firm demand charge and the monthly fixed charge for these customers, in order to increase the recovery of fixed and demand costs. The monthly fixed charge for Rate 3 customers would increase to $150.00 from the current level of $100.00. The charge for Rate 3 combined customers would increase to $175.00 per month from the current level of $125.00. The firm delivery commodity charge will also be increased in the test year. No changes were proposed to the interruptible delivery commodity charge range in the 2007 test year. Rate 3 Firm customers will see an increase of $4,131 (9%) to their annual distribution charge.

For the Rate 4 – General Service Peaking rate class, NRG proposed to increase the monthly fixed charge by $2.00, from $10.75 to $12.75 per month with a decrease to the first block delivery charge and an increase to the second block delivery charge in the April through December period. The decrease in the first block rate helps to offset the impact of the higher monthly fixed charge. Rate 4 customers will see an increase of $306 (15%) to their annual distribution charge as a result of this change.

For the Rate 5 – Interruptible Peaking Contract Rate, NRG proposed to increase the monthly fixed charge from $100.00 to $150.00 and increase the interruptible delivery commodity charge. There was also a change proposed to the charge related to the minimum annual volume penalty rate. Rate 5 customers will see an increase of $1,096 (9%) to their annual distribution charge.

The table below summarizes the proposed changes to the monthly fixed charge across the different rate classes.

Rate Class	Current Fixed Charge	Proposed Fixed Charge	Difference
1	$9.50	$11.50	$2.00
2	$10.75	$12.75	$2.00
3	$100.00	$150.00	$50.00
Rate 3 Firm	$125.00	$175.00	$50.00
4	$10.75	$12.75	$2.00
5	$100.00	$150.00	$50.00

NRG also proposed a change to the System Gas Fee in Schedule A of its rate handbook, which provides the gas supply charges that are applicable to all system customers served under rates 1, 2, 3, 4 and 5. NRG proposed to increase the system gas fee from $0.001159 per m^3 to $0.001828 per m^3 to cover 100% of the associated allocated costs.

Board Staff sought an explanation from NRG as to what constitutes a “rate shock”, a concept that NRG intends avoiding as outlined in their guiding principles to rates and service terms. NRG could not provide specific criteria of what constituted a rate shock and considered the concept to be subjective. Board Staff specifically questioned NRG with respect to the increase in distribution charges for Rate 2 customers. The Company did agree that the impact on Rate 2 customers was approaching rate shock.

The Company indicated that it had taken steps to mitigate the impact on Rate 2 customers. Elaborating on this measure, the Company stated that the revenue-to-cost ratio of Rate 2 customers is lower than previously Board approved ratios.

Considering the expected decline in number of Rate 2 customers, Board staff questioned the possibility of merging Rate 2 customers with some other rate class. The Company argued that Rate 2 customers pay a much lower rate than some other rate classes and the problem was that they could neither be reclassified as contract customers due to insufficient volumes nor considered for interruptible services.

The Company also stated that the proposal to increase the monthly charge is revenue neutral in each rate class. NRG further added that it will continue to review the level of the fixed monthly charge consistent with the practice of other utilities such as Enbridge and Union.

Considering the impact of a project the size of the ethanol facility, IGPC wondered whether NRG would design a new rate class specifically for them. NRG in its reply confirmed the need for a separate rate.

Board Findings

The Board approves the rate design changes as proposed by the Company and agrees that the alignment of cost incurrence with cost recovery is in keeping with sound rate design principles.

DEFERRAL AND VARIANCE ACCOUNTS

NRG has the following five Board-authorized deferral accounts:

- Purchased Gas Commodity Variance Account (PGCVA)
- Purchased Gas Transportation Variance Account (PGTVA)
- Gas Purchase Rebalancing Account (GPRA)
- Gas Cost Difference Recovery Variance Account (GCDRVA)
- Regulatory Expenses Deferral Account (REDA)

Balances in the PGCVA and REDA have been determined in the same manner as in the past. The REDA is projected to have a debit balance of $147.96 at the end of fiscal 2005. NRG proposes that the REDA be continued into the 2007 test year and that it continue to record costs associated with participating in generic hearings and in Union Gas proceedings. The balance in the PGCVA as of September 30, 2005 was a debit of $104,565.91 including a debit of $1,944.76 in accumulated interest. NRG has proposed that the PGCVA be continued into the 2007 test year. The reference price will continue to be adjusted on a quarterly basis through the QRAM process.

The PGTVA reference price of $0.021848/m^3 approved as part of the RP-2004-0167 Decision with Reasons dated December 20, 2004 for fiscal 2005 rates remains in effect for fiscal 2006. NRG has proposed to dispose of the balances in this account on completion of fiscal 2006. As part of this proceeding, NRG has proposed to change the reference price used when calculating the balance recorded in the PGTVA to $0.019029/m^3 for fiscal 2007. This is the projected rate that is required to recover the forecast gas transportation costs payable to Union.

The GPRA is used to record increases or decreases in the value of gas inventory available for sale to sales service customers due to changes in NRG's PGCVA reference price. The monthly inventory balances used in calculation of the GPRA are based on a deemed level of unaccounted for gas (UFG) of the total throughput volume. NRG has proposed that the GPRA be continued in the 2007 test year, based on a deemed UFG of 0.0%.

The GCDRA was approved by the Board in the RP-2004-0167 Decision with Reasons dated December 20, 2004. It was established to track the variance between the amount collected from ratepayers ($531,794), as authorized by the Board in RP-2004-0167/EB-2004-0413, and $177,265 in each of three years. As part of this application, NRG has proposed that the GCDRA be continued for the 2007 test year. This will be the third and final year for the GCDRA. NRG has requested that the rate of $0.008230/m^3 be continued.

At the start of the hearing, NRG sought an approval from the Board to set up a Refinancing Cost Deferral Account (RCDA) to track breakage and penalty costs that it has incurred to refinance its debt. The updated evidence of NRG indicated a debit balance of $219,116.85 including a debit of $5864.46 in interest at the end of fiscal 2006. NRG has proposed to recover the balance related to the refinancing account by amortizing the costs, including interest, over the remaining life of the new loan beginning in the fiscal 2007 test year.

NRG has proposed to change the methodology used to calculate interest rates for deferral and variance accounts. It has proposed to use the Bank of Nova Scotia prime interest rate in effect at the time of each QRAM filing as the basis for the interest rate to be used in the subsequent quarter.

Board Findings

The Board approves changes to the reference price in the Purchased Gas Transportation Variance Account (PGTVA), from $0.021848/m^3 to $0.019029/m^3 for fiscal 2007.

The Board approves NRG's request to continue the Gas Purchase Rebalancing Account (GPRA) in the 2007 test year, based on a deemed unaccounted for gas of 0.0%.

The Board approves the setting up of the Refinancing Cost Deferral Account (RCDA) to track breakage fees and other related costs. However, the balance in the account will be as stated in this decision. NRG will include a total amount of $204,712.66 in this account, including $5,478.93 in accumulated interest at the end of fiscal 2006. NRG will recover this amount by amortizing it over a period of 60 months beginning in the fiscal 2007 test year.

The Board does not accept NRG's proposal to change the methodology to calculate interest rates for deferral and variance accounts. This is part of a separate generic proceeding (EB-2006-0117) and will be tabled before the Ontario Energy Board Rates Committee in October 2006. The Decision by the Rates Committee will determine the appropriate interest rates for use in variance and deferral accounts.

SUMMARY AND RATE ORDER

NRG claims a delivery-related revenue deficiency of $135,879 for fiscal 2007. This revenue deficiency/sufficiency is adjusted to reflect the following Board findings in this decision.

- Lower advertising expenses of $8,008 in fiscal 2007
- Reduction of replacement cost of one van ($38,000)
- Reduction of common equity ratio from 50% deemed to 42%
- An equity risk premium of 50 basis points over Enbridge Gas Distribution Inc.
- Reduction of $14,404.19 in refinancing costs including interest
- Amortization of refinancing costs over a 60-month period as compared to 53 months as proposed in the application

The Company is directed to submit a draft rate order, with appropriate documentation, containing the following:

- Financial schedules for the test year reflecting the Board's findings in this decision, i.e. Rate Base, Operation Revenue, Cost of Service, Capitalization/Cost of Capital, Determination of Revenue Sufficiency/Deficiency.
- Rate schedules for 2007 flowing from the above calculations and other Board findings in this decision.
- A list of deferral/variance accounts approved for the 2007 fiscal year.
- Notices to customers to accompany the first bills reflecting the new rates and bill adjustments.

DATED at Toronto, September 20, 2006

ORIGINAL SIGNED ON
BEHALF OF THE PANEL BY

Gordon Kaiser
Presiding Member and Vice Chair

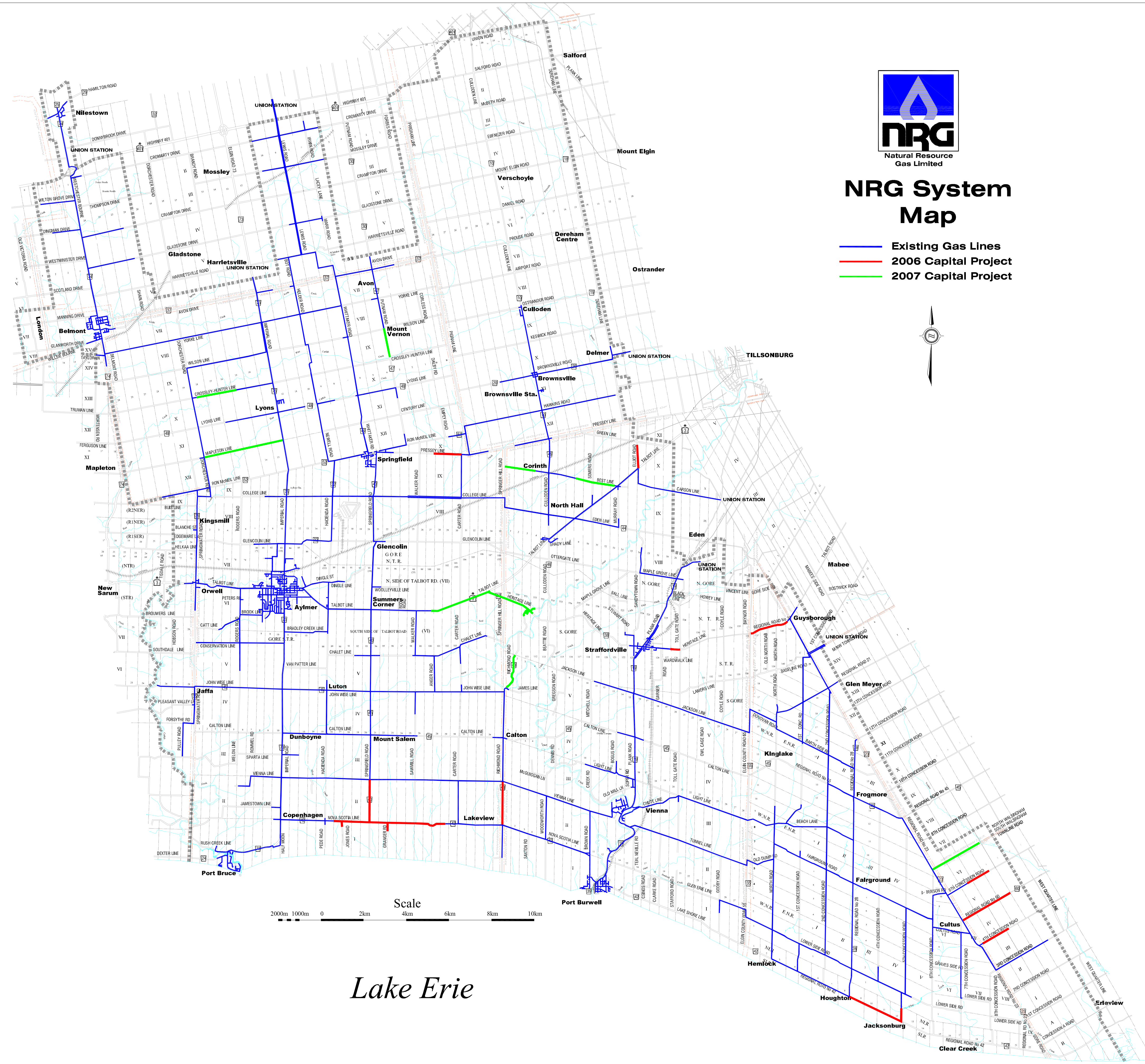
SCHEDULE A TO

DECISION AND ORDER

BOARD FILE NO. EB-2005-0544

NRG SYSTEM MAP

DATED SEPTEMBER 20, 2006



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SCHEDULE B TO

DECISION AND ORDER

BOARD FILE NO. EB-2005-0544

CHART: CHANGES TO APPROVALS REQUESTED

DATED SEPTEMBER 20, 2006

Schedule B

CHANGES TO APPROVALS REQUESTED

	Request	Approval	Reference
CAPITAL EXPENDITURES			
Automotive	Replacement of 5 vehicles at a cost of $188,000	Replacement of 4 vehicles at a cost of $150,000	p.9
COST OF SERVICE			
Cash Rebate and Lead Pay Programs	100% to regulated business	85% to regulated, 15% to ancillary	p.18
Advertising Expenses[1]	$74,861.00	$66,853.00	p. 18 & 19
CAPITAL STRUCTURE & COST OF CAPITAL			
Debt to Equity Ratio	65-35	58-42	p.26
Equity Risk Premium	150 bps	50 bps	p.26
FINANCING & REDEPLOYMENT COSTS			
Junsen Debenture	$20,281.80	$6,263.14	p.32
Interest Cost	$5,864.46	$5,478.93	p.32
Amortization of refinancing costs	53 months	60 months	p.32
COST ALLOCATION			
Marketing Programs	100% to regulated	If involves selling natural gas equipment – proportion according to revenue between ancillary and regulated	p.34

[1] Reflects reduction of $4,291 to the lead pay program and $3,717 to the cash rebate program.

OEB, Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors
December 2006

Ontario Energy Board

Report of the Board

on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors

December 20, 2006

Table of Contents

1 Introduction

Purpose

In its Report on the 2006 Electricity Distribution Rate Handbook[1], the Board committed to conducting a review of the issues involved in establishing the cost of capital. In 2006, the Board also committed to implementing a multi-year rate plan for distributors (the "Rate Plan") which included an incentive mechanism to adjust rates over the period 2007 to 2009 and a commitment to develop a long-term rate setting framework by 2009. The incentive mechanism for rates over the period 2007 to 2009 is called the 2nd generation incentive regulation mechanism (2nd Generation IRM).

Board Staff have undertaken research, commissioned expert advice and consulted with stakeholders on the methods for setting the cost of capital and 2nd Generation IRM. These activities began in April 2006 and have culminated in this policy report of the Board.

This report sets out the Board's approach to cost of capital and the 2nd Generation IRM and presents guidelines for distributors to use in preparing their rate applications.

Organization of this Report

The report is organized as follows. The Board's policy for and analysis of cost of capital and 2nd Generation IRM are outlined in Section 2 and Section 3, respectively. Both sections provide brief descriptions of the matters being addressed, the Board's policies and rationale, and summaries of the issues and options raised in consultations. Section 1 outlines in more detail how and when the adjustments to distribution rates will be

[1] RP-2004-0188, May 11, 2005

implemented. Section 5 provides a summary. Guidelines associated with the policies set out in this report are contained in the Appendices.

2 Cost of Capital

The cost of capital for Ontario's electricity distributors is best understood in the context of their history. Up until 1999 the electricity distributors were mostly municipal organizations that were regulated by Ontario Hydro; from 1972 until 1998 the authority for this regulation was provided by the *Power Corporation Act*. In 1998, the passage of the *Energy Competition Act, 1998* gave the Board increased powers and a broader mandate, including responsibility for regulating the monopoly electricity transmission and distribution systems.

Since 1999, the cost of capital for distributors has been governed by the Board's Decision with Reasons in proceeding RP-1999-0034. This decision established a size-related capital structure for distributors and set the return on equity (ROE) at 9.88% based on the method used by the Board at that time to regulate natural gas utilities. This ROE method was a modified version of a method described in a report provided by Dr. William T. Cannon in 1998. That report was entitled "A Discussion Paper on the Determination of Return on Equity and Return on Rate Base for Electricity Distribution Utilities".

The subsequent phase-in of the Market Adjusted Revenue Requirement and the rate freeze imposed by Bill 210 in 2002 meant that further reviews of the cost of capital for electricity distributors were unnecessary. At about the same time, however, the Board did hold a review of ROE in response to applications from the gas distributors (RP-2002-0158). The Board found that there was no compelling reason to adopt a different cost of capital method for the natural gas distributors.

During the development of the 2006 Electricity Distribution Rate (EDR) Handbook the Board approved the continued use of the mechanistic update, consistent with the method used by Dr. Cannon in his 1998 paper, to set both allowed ROE and deemed debt rates for 2006 rate applications (the "current approach"). The updated ROE was determined by the Board for 2006 rates to be 9.00%. The stratification of debt/equity by distributor size, as a proxy for risk, was retained. The size-related deemed debt rates were updated in 2006 but the deemed capital structures were not changed.

Table 1 and Table 2 provide the allowed ROE, capital structure and deemed debt rates for distributors for the 2006 rate year, as described in the 2006 EDR Handbook.

Table 1: Allowed ROE

Average of 3- and 12-month *Consensus Forecasts* outlook for 10-year Government of Canada bond rates	4.75%
Average difference during April 2005 between 10- and 30-year Government of Canada bond yields (Source: Bank of Canada)	0.45%
Equity risk premium	3.80%
Allowed return on equity	**9.00%**

Table 2: 2006 Rates Capital Structure and Debt Rates

Rate Base	Deemed Capital Structure		Deemed Debt Rate (DR)
	Debt (D)	Equity (1-D)	
> $1.0 billion	65%	35%	5.8%
$250 million - $1.0 billion	60%	40%	5.9%
$100 million - $250 million	55%	45%	6.0%
< $100 million	50%	50%	6.25%

The Board's previous reviews of cost of capital reveal a general agreement that regulated distributors are less risky than the broader market on which the rating agencies primarily focus. Beyond that, however, there is a large potential range of risk and varied opinion on the best way of representing that risk in the current circumstances of Ontario's distribution companies. The Board is guided in this matter by the need to reflect appropriately risk in rates such that investors are provided a reasonable opportunity to earn a fair return and consumer interests are protected. The Board has looked to the advice of experts to assist in the development of an effective policy for setting the cost of capital for 2007 and beyond. In addition, the Board considered regulatory practice in several Canadian and United States jurisdictions.

2.1 Capital structure

Policy and Rationale

The Board will deem a single capital structure for all distributors for rate-making purposes. The Board has considered the concerns that have been expressed by distributors and certain members of the investment community that a reduction in equity thickness or return might result in a lower credit rating. As discussed below, the Board is not convinced these concerns warrant differentiated deemed capital structures. Therefore, **the Board has determined that a split of 60% debt, 40% equity is appropriate for all distributors.**

To date, the Board has used four size-related deemed capital structures for rate regulation of electricity distributors. As noted previously, this was based on the study conducted by Dr. Cannon for the development of the first Distribution Rate Handbook. In his study, Dr. Cannon noted that:

> Conceptually, [distributor] deemed capital structure ratios for rate-regulation purposes and/or their allowed returns on equity should vary to reflect the extent of the business risks to which each MEU is exposed. Higher relative business risks will imply less debt-carrying capacity and hence call for higher deemed common equity ratios (CERs). Furthermore, if the higher CER does not fully compensate for a MEU's relatively higher business risk, then the allowed return on equity (ROE) should also be adjusted upward to compensate MEU owners for the relatively higher total investment risk that their ownership stakes are exposed to.

However, Dr. Cannon recognized that it was not practical to review the capital structure for each distributor. He concluded that it was appropriate to stratify distributors into a limited number of groupings of similar risk. Further, he identified a number of characteristics that, in his view, affected the risk profile of a distributor:

(1) The size of the distributor's operations, assets, and revenue base;
(2) The nature and stability of the distributor's customer mix;
(3) Degree of competition from other fuels;

(4) The age and condition of the physical distribution system;
(5) Local climate peculiarities;
(6) The geographic size and isolation of the distributor's service area; and
(7) The availability of back-up self-generation capacity.

However, in his final analysis, Dr. Cannon settled on factors (1) and (6). Other criteria were rejected on the basis that the influence of each factor was generally small and/or “diversifiable”. Factors (1) and (6) were assessed to be recognizably correlated with each other, and, as a result, risk categorization based on size was believed to be warranted in 1998.

The electricity distribution sector has undergone significant change over the last eight years, and that change supports the move from size-related capital structures to a common capital structure. In particular, there has been considerable restructuring through mergers and acquisitions. While there were over 300 distributors in 1998, there are now less than 90. While there are some very small distributors in existence, the trend has been toward fewer and larger distributors. A recent Government announcement of a new two-year transfer tax exemption may spur further consolidation. This trend underscores the need to ensure that the Board does not create barriers to consolidation. In the Board’s view, one of those barriers is the differing capital structure of distributors.

Larger distributors generally supported the 60:40 structure as it means little or no change for them. However, smaller distributors expressed a number of concerns and disagreed with the proposal of a single capital structure.

Many distributors commented that size was an important measure of risk that must continue to be reflected in the cost of capital. Comments were made that small distributors face greater business risk than large distributors when a significant fraction of their load is from a single customer or when there is load concentration in a limited number of sectors (e.g. forestry, agriculture, etc.). According to this view, for a small distributor, a downturn in the sector may also result in consumers and local businesses (restaurants, stores, etc.) moving away, while larger distributors may operate in more diversified local economies and hence be better protected from a sector downturn.

The Board notes that load concentration risk, which was the primary focus of distributor concerns, is not necessarily related to distributor size. Horizon Utilities, Oakville Hydro and EnWin Powerlines are examples of mid-sized distributors with concentrated loads. As discussed previously, the four size-based categories have been in effect since industry restructuring and distribution rate unbundling. Based on changes to the sector over the last eight years and data from distributors’ operations since 1999 the Board concludes that size is not a key determinant of, or proxy for, risk.

This conclusion is corroborated by the Board’s examination of 2005 financial data filed by electricity distributors, which show that the distributors exhibit a variety of actual debt-equity structures. According to the data, about one quarter of the small distributors have leveraged themselves with debt to levels in excess of 50%. These distributors do not appear to be experiencing particular financing concerns as a result of this debt load.

A distributor, regardless of size, when planning and making decisions to manage its business risk, will organize its financing in line with its business needs.

The Board concludes that utility size no longer represents an accurate proxy for risk. As a result, there is no basis upon which ratepayers should be required to bear different costs, associated with different capital structures, on the basis of distributor size. The question the Board must ask is whether ratepayers of smaller distributors should pay higher rates than those of larger distributors because of a thicker equity component. For these reasons it is the Board’s view, that for ratemaking purposes, a single capital structure for all distributors is appropriate.

To avoid the unintended consequences of transition causing gross mismatch between actual and deemed capital structure, the Board has determined that a staged implementation will be used. This is discussed in sub-section 4.1, below. In addition, if the change in capital structure, and the increase in debt, leads to higher costs for new third-party debt, those higher costs will be reflected in rates. This is explained further in section 2.2.1.

The Board does recognize that some distributors may face materially different risks for the reasons identified by Dr. Cannon. However, it is incumbent upon the distributor to provide evidence of those risks. Whether the Board might address these risks through a different capital structure or a variance in the equity risk premium would depend on its consideration of the evidence provided. Distributors that believe they are in this category may raise this issue at rebasing. Distributors should also review the Board's letter of December 19, 2006 which deals with the timing of rebasing. Attached to that letter is a discussion paper on a screening methodology to establish a rebasing schedule for electricity distributors, including the option of self nomination.

Issues and Options Raised in Consultation

Most consumer groups support the single capital structure. During the technical conference, one stakeholder acknowledged that "small cap" firms do normally attract a risk premium in the market, but stated that information asymmetry is a major reason for this. This stakeholder further commented that information asymmetry occurs when an investor knows less about a small firm than would be the case with a large firm. However, in this context, information asymmetries are immaterial for regulated firms as they all report the same data to the regulator routinely, and publicly.

Some stakeholders expressed concern that during the transition to the new deemed structure distributors will restructure and take on more debt, possibly violating existing debt covenants or risking credit rating downgrades. However, the Board notes that a distributor's actual structure does not have to be the same as its deemed capital structure.

Larger distributors (primarily Hydro One Networks and members of the Coalition of Large Distributors (the CLD)) have not identified any concerns with the 60:40 structure. Smaller distributors argued in favour of the four size-based categories or, in the alternative, the two size-based categories recommended by staff's consultants, Dr. Lazar and Dr. Prisman. During the technical conference, Dr. Lazar and Dr. Prisman confirmed that their suggested two-category structure is "transitional" to a single structure. The Board is of the view that a single end-state structure with a method of transitioning towards it from the current four structures is more appropriate.

2.1.1 Debt Component

The 60% debt component is comprised of short-term and long-term debt. To date, short-term debt has not normally been factored into the setting of electricity distribution rates. However, it has been included in rate setting for natural gas distributors. In the gas sector, an amount referred to as "unfunded short-term debt" is calculated to balance total financing with rate base.

Policy and Rationale

The Board has determined that short-term debt should be factored into rate setting, and that a deemed amount should be included in the capital structures of electricity distributors. **The short-term debt amount will be fixed at 4% of rate base**.

Based on filings of distributors pursuant to the Board's Electricity RRR and in 2006 rate applications, it is clear that many distributors use short-term debt. The actual average for the industry is about 4%. Some distributors use it extensively as a substitute for long-term debt. This may be advantageous in a period characterized by low inflation and interest rates, but such a practice exposes the distributor – and its customers – to inordinate risk if rates climb. This risk may be reduced if the distributor prudently converts the short term debt to longer-term debt when rates start to rise.

Many distributors are using short-term debt to finance their operations. The Board believes that this should be reflected in rates. Short-term debt is generally less expensive than long-term debt and generally provides greater financing flexibility. Rates on short-term debt can be more volatile than rates on long-term debt and therefore the Board believes it is in the interests of distributors and ratepayers for the amount of short-term debt to be set at a deemed level.

Issues and Options Raised in Consultation

With respect to the short-term debt component of rate base, three other options were considered:

- No short-term debt (the status quo);
- Actual short-term debt component for each distributor; and
- Short-term debt set at 8% of the rate base.

No short-term debt

As a general principle for ratemaking purposes, the Board believes that the term of the debt should be assumed to be similar to the life of the assets that are to be acquired with that debt. This suggests that, in theory, for an industry with long-lived assets, the majority of debt should be long-term. However, in reality, some short-term debt is a suitable tool to help meet fluctuations in working capital levels. Therefore, exclusion of some consideration for short-term debt in the distributors' capital structures going forward would not be appropriate.

Actual short-term debt

While there was limited discussion of this approach, another option would be to use the actual short-term debt expressed as a percentage of the distributor's capital structure.

Although using a distributor's actual short term debt component may seem to be a more accurate approach, it may be problematic. Short-term debt is optimally used as an interim solution for managing a firm's financing requirements. It may fluctuate, although generally within a limited range. Using a firm's actual short-term debt component would be administratively challenging given the number of electricity distributors and the associated volume of data that would need to be reported and verified.

Short-term debt component set at 8%

In its July 25th discussion paper staff described an option of deeming short-term debt, needed to finance working capital, at 8% of rate base. The 8% figure was based on staff's review of Hydro One Distribution's lead-lag study filed in its 2006 EDR rate case.[2] In that study, Hydro One Networks showed that its working capital requirement was $288.5 million (cash of $265.6 million plus materials and supplies inventory of $22.9 million) out of a distribution rate base of $3,711.7 million, or about 8% of its distribution rate base. Staff explained this derivation during the technical conference.

There was confusion as to whether this proposal would also alter the working capital allowance (WCA) from the current formula (15% of the cost of power and (defined) controllable expenses). Staff explained that this was not the case. The Board committed, during the development of the 2006 EDR Handbook, to look at the determination of the WCA before 2008, and this is documented in the Board's Business Plan.

While a higher component of short-term debt would, all other things being equal, lower the cost of capital, it may be seen as financially constraining for distributors. Based on comments to this effect made by distributors, the Board believes that a smaller short-term debt component of rate base is appropriate.

[2] Table 1 on Hydro One's RP-2005-0020/EB-2005-0378, Exhibit D1, Tab 1, Schedule 1, Page 2 of 5.

2.1.2 Equity Component

Policy and Rationale

The Board has determined that distribution rates shall reflect 40% **common equity. There will be no adjustment for a preferred share component of equity in rates, although distributors can, if they choose to do so, use preferred shares within their financing structure**.

Issues and Options Raised in Consultations

One distributor suggested that preferred shares be treated as debt, so that the deemed capital structure would be 40% common equity, up to 4% preferred shares, and the remainder as long- and short-term debt. It was argued that common and preferred shares are different.

The Board is of the view that while common and preferred shares differ, preferred shares and debt also differ. The Board is not persuaded that preferred shares should be treated as debt in the deemed capital structure for ratemaking purposes. The fact that there is no requirement for the actual debt and equity structure of a distributor to match the deemed amount in rates means that distributors can use preferred shares at their discretion.

2.2 Debt Rates

2.2.1 Long-term debt

Long-term debt is a major component of a distributor’s capital structure. As noted previously, for ratemaking purposes the term of the debt should be assumed to be compatible with the life of the asset. With electricity distributors, the asset life can extend beyond 30 years. Typically, debt is incurred at the time when assets are put in service and the cost of that debt is at the prevailing market rate. This means that a distributor may be holding long-term debt at rates that differ according to when the debt was incurred. This is often called “embedded debt.”

In Ontario, distributors have two main sources of debt financing: affiliates (including owners); and third parties, such as commercial banks.

Policy and Rationale

For rate-making purposes, the Board considers it appropriate that further distinctions be made between affiliated debt and third party debt, and between new and existing debt.

The Board has determined that for embedded debt the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt.

The Board has determined that the rate for new debt that is held by a third party will be the prudently negotiated contracted rate. This would include recognition of premiums and discounts.

For new affiliated debt, the Board has determined that the allowed rate will be the lower of the contracted rate and the deemed long-term debt rate. This deemed long-term debt rate will be calculated as the Long Canada Bond Forecast plus an average spread with “A/BBB” rate corporate bond yields. The Long Canada Bond Forecast is comprised of the 10-year Government of Canada bond yield forecast (*Consensus Forecast*) plus the actual spread between 10-year and 30-year bond yields observed in Bank of Canada data. The average spread with “A/BBB” rate corporate bond yields is calculated from the observed spread between Government of Canada Bonds and “A/BBB” corporate bond yield data of the same term from Scotia Capital Inc., both available from the Bank of Canada.

For all variable-rate debt and for all affiliate debt that is callable on demand the Board will use the current deemed long-term debt rate. When setting distribution rates at rebasing these debt rates will be adjusted regardless of whether the applicant makes a request for the change.

The deemed long-term rate will be calculated using data available three full months in advance of the effective date of the distribution rate change. The method that the Board will use to update this rate is detailed in Appendix A.

The approach to setting the rate for embedded debt at its prior approved rate is based on the fact that those rates have already been reviewed in previous cases and been determined to be appropriate.

The approach to setting the rate for new debt differs as between third party and affiliate lenders, so as to recognize that in affiliate transactions there is an opportunity for terms to be negotiated at less than “arm’s length”, which could result in less favourable terms and conditions. When a distributor is financed by a third party, however, it is expected that the distributor will obtain commercial terms and conditions, including market rates.

Distribution rates will be adjusted for embedded debt only when the distributor is rebased and only up to the maximum allowed by the approved capital structure and at the weighted average cost of the embedded debt. During the incentive period, deemed debt rates will remain unchanged.

Issues and Options Raised in Consultations

Dr. Lazar and Dr. Prisman proposed that the deemed long-term debt rate be determined as the riskless rate plus the average spread between a sample of “A/BBB” rated corporate bonds of 5, 10 and 20 year maturities and the corresponding Government of Canada bonds. The riskless rate would be approximated by averaging estimates of the

5-, 10- and 15-year zero-coupon Government of Canada bond yields from publicly available data (e.g. from the Bank of Canada).

A concern was expressed that the 5- 10- and 15-year zero-coupon bond yields do not adequately match the life of the distribution assets. Stakeholders suggested that the bond yields should include longer terms up to 30 years. The Lazar/Prisman proposal and the method that the Board has adopted do include 30-year bond yields in the calculation of the deemed long-term debt rate.

The Board is of the view that while the Lazar/Prisman method has merit, the approach is materially more complicated and is also unfamiliar to stakeholders. In addition, the current method produces a similar result to that which arises from the Lazar/Prisman method. Maintaining the current method provides continuity and consistency for distributors, and the Board concludes that there is no compelling reason to change the method for setting the deemed long-term debt rate.

2.2.2 Short-term debt

“Short-term debt” normally denotes demand notes or debt that has a term of one year or less. On November 28, 2006, the Board issued a letter communicating its approved method for calculating interest rates for regulatory accounts. This provides a method to compute a short-term rate which is acceptable for short term debt.

Policy and Rationale

The Board has determined that the deemed short-term debt rate will be calculated as the average of the 3-month bankers’ acceptance rate plus a fixed spread of 25 basis points. This is consistent with the Board’s method for accounting interest rates (i.e. short-term carrying cost treatment) for variance and deferral accounts. The Board will use the 3-month bankers’ acceptance rate as published on the Bank of Canada’s website, for all business days of the same month as used for determining the deemed long-term debt rate and the ROE.

For the purposes of distribution rate-setting, the deemed short-term debt rate will be updated whenever a cost of service rate application is filed. The deemed short-term debt rate will be applied to the deemed short-term debt component of a distributor's rate base. Further, consistent with updating of the ROE and deemed long-term rate, the deemed short-term debt rate will be updated using data available three full months in advance of the effective date of the rates.

Issues and Options Raised in Consultations

The topic of short-term debt rates was subject to little comment due to the Board's separate process on interest rates to be applied to deferral and variance accounts. Any issues raised have been addressed as part of the Board's consideration of that issue.

2.3 Return on Equity

2.3.1 Return on Common Equity

The return on common equity compensates investors for the opportunity cost of providing share capital to a distribution business. The cost of that capital will vary with the perceived risk of the investment. In general, the rate of return to the investor should be appropriate to the risk of the distribution company compared to that in the market.

Policy and Rationale

The Board has determined that the current approach to setting ROE will be maintained. ROE will be determined based on the Long Canada Bond Forecast rate plus an equity risk premium (ERP). The method the Board will use to update ROE is detailed in Appendix B.

The Board's current approach has been in place for six years. In this consultation process several variations on the underlying inputs and assumptions to the current method were reviewed, and one alternative method was reviewed. The review of inputs and assumptions offered a range of ROE results between 8.37% and 11.5%. The alternative method produced ROE results ranging from 5.78% to 7.02%. This alternative method would have required more time and greater costs for its implementation. Given the issues and options raised in the consultation, the Board concludes that none of the approaches reviewed is better than the Board's current method.

The Board's method will continue to include an implicit premium of 50 basis points (0.5%) for floatation and transaction costs. This premium is included in, and not an addition to, the ERP. The Board notes that this has been the case ever since the Board first introduced the premium in the early 1990s, and that similar treatment is used by other Canadian regulators.

The Board will also clarify the starting point for the update. The update method was established in 1999 as part of a review of cost of capital. Therefore, it is appropriate to use the ROE calculated at that time as the starting point. This figure was 9.35% and was determined by the Board in Hydro One Network Inc.'s RP-1998-0001 Decision. The Board will use 9.35% ROE as the starting point for the update.

Issues and Options Raised in Consultations

Many stakeholders identified different ways to establish what they considered to be a more appropriate ROE; however, the majority of them indicated that if their own approach was not adopted by the Board, then the status quo was preferred.

An Alternative Approach to the Risk-Free Rate and ERP under CAPM

Dr. Lazar and Dr. Prisman recommended an alternative approach that would estimate ROE as the sum of a risk-free rate and an ERP estimated using the well-known Capital Asset Pricing Model (CAPM). They proposed estimating the ERP based on a proxy sample of firms that are similar to electricity distributors. They proposed to set the risk-free rate using forward rates based on zero-coupon bond yield estimates.

With regard to the risk-free rate, the recommended method would take advantage of new data which the Bank of Canada began to provide in 2004. These new data are estimates of the zero-coupon yield curves that may be inferred from the traded prices of Government of Canada bonds. Zero-coupon bonds are bonds that do not pay any yearly interest to the holders; they merely promise to repay the holders the face value of the bond at some future date.

As noted, Dr. Lazar and Dr. Prisman recommended an approach that relies solely on the use of the CAPM. While it was noted that CAPM has some deficiencies, Dr. Lazar and Dr. Prisman expressed their confidence that it is the soundest of the conventional methods (notwithstanding more recent and more complex methods based on Arbitrage Pricing Theory). They also noted that relying solely on CAPM would avoid the need for weighting of results, which is generally acknowledged as arbitrary. From their analysis, they estimated betas (a measure of the relative riskiness of the firm or sector against the market in general) of about 0.3 to 0.4.[3]

The proposed approach would result in a range of ROEs from 5.78% to 7.02% based on current data. With further analysis and some refinements to the proxy group of firms, staff calculated an ROE of 8.37% based on current data. A coalition of medium-sized distributors[4] retained Dr. Morin and Energy and Environmental Economics, Inc. who presented a study which used data from Dr. Lazar's and Dr. Prisman's report (and hence relied on CAPM), but used a different formulaic calculation of ROE. They calculated an ROE in the range of 9.8% to 10.4%.

Stakeholders criticized the Lazar/Prisman approach on the basis of a mistaken understanding that the riskless rate was estimated based on medium-term rates – the average of 5-, 10- and 15-year zero-coupon bond yields. Stakeholders suggested that this was inappropriate and that a longer term is appropriate to match the expected equity investment and asset life horizons for electricity infrastructure. In fact, the method recommended by Dr. Lazar and Dr. Prisman does incorporate data from 30 year bonds; their proposed method of averaging the 30-year zero-coupon yield curve focuses on the yields at 5, 10, and 15 years. There was also criticism of the short time series used in the analysis. While traditionally 60 year data is used, the consultants used one- to five-year data sets for the estimation of the CAPM beta and five and ten years for the market risk premium.

The sensitivity of the Lazar/Prisman approach to various assumptions and the lack of clearly comparable firms, have convinced the Board to maintain the current approach to setting ROE.

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[3] A beta of 1 indicates equal riskiness with the market.

[4] Bluewater Power Distribution Corporation, Chatham-Kent Energy, Newmarket Hydro Ltd. and Welland Hydro-Electric Systems Corp

Traditional Approaches, Different ROE Estimates

Some distributors retained consultants that provided different ROE estimates using the traditional methods. Ms. Kathleen McShane of Foster Associates, Inc., the consultant for Hydro One Networks Inc., provided a cost of capital study that suggested an ROE of 10.5% is appropriate. The consultant for the Electricity Distributors Association, Mr. Robert J. Camfield of Christensen Associates Energy Consulting, tabled a study that suggested a range of ROEs of 10.2% to 11.5%. Both of these studies relied on the three standard methods of determining ROE: CAPM; the Discounted Cash Flow approach (DCF); and Comparable Earnings (CE). These studies relied on a longer time series of data. However, they also employed, to a lesser or greater extent, U.S. data in addition to Canadian data. Distributors have argued that they must compete for financing in global markets, and hence that use of U.S. data is justified on a "comparable earnings" basis. However, inclusion of U.S. data is a source of controversy, as allowed returns in the United States have typically been higher than those approved in many Canadian jurisdictions, and the market return is higher in the United States.

Some distributors argued that higher ROEs were needed because business risk for distributors has increased since 1999 – in large part due to governmental and regulatory policies which have hindered distributors' opportunities to earn a full rate of return. However, this was criticized by consumer groups on the basis that any business risk was particular to the early part of this decade, that distributors' revenue requirements have reflected a full market based rate of return since 2005, and that the multi-year rate plan should provide a predictable and stable regulatory environment under which distributors will be faced with "normal" risk.

Dr. Booth, a consultant retained by several consumer groups, supported a similar approach to that used by Dr. Lazar and Dr. Prisman, but expressed preference for the Board's current method because it better balances stakeholder and investor interests – and that this "balance" is relied upon in many Canadian jurisdictions. Dr. Booth commented that, notwithstanding his acceptance in the interim of an ROE calculated by Dr. Cannon's method, if he were to do the analysis directly he would end up with a result below 8%. At the technical conference, Dr. Booth observed that, in his view, it is just a matter of calculating using correct data. The fact that his result, and the results of Dr. Lazar and Dr. Prisman (as well as that of Professor Wilbur for Union Gas recently) are basically the same is merely a function of each doing what amounts to the same calculation, even if they come at it different ways.

While distributors supported the significantly higher ROE estimates of their consultants, many stakeholders – both distributors and consumer groups – recommended the retention of the Board's current approach rather than the adoption of Dr. Lazar's and Dr. Prisman's method. This suggests to the Board that the current approach results in a return sufficient for distributors to continue to attract capital. Therefore, the Board has determined that the current approach to setting ROE will be maintained.

2.3.2 Premium for Infrastructure Investment

The Board notes that staff's proposal to add a premium to the ROE for electricity distributors to provide an incentive for new infrastructure investment was not supported. While consumer groups generally rejected the need for an investment premium, distributors rejected the ROE premium on only new investment, but supported an overall increase in ROE to support new capital investment.

Some distributors did confirm that they are forecasting increased infrastructure investment for distribution system upgrades and expansion. The Board will be developing the criteria it should use to determine the Rate Plan groupings. The Board may consider, amongst other criteria, a measure of distributor capital investment to select distributors for rate rebasing in each of 2008, 2009, and 2010. Regardless, the Board is of the view that the extent and amount of capital upgrades required to ensure system reliability deserves further examination. This will be captured in a Board study undertaken in the 2007/08 fiscal year. Upon completion of this study, the Board may examine need for and appropriate form of any capital investment incentives. **The Board is not convinced that a premium is warranted at this time**.

Issues and Options Raised in Consultations

The issue of capital investment under incentive regulation is discussed in sub-section 3.6 below.

2.3.3 Implementation of Cost of Capital Policy

Changes to a distributor's cost of capital will be implemented beginning with applications for 2008 distribution rates.

A distributor's transition to the common deemed capital structure will start in 2008 regardless of whether the distributor rebases in that year or continues to be subject to 2nd Generation IRM. Further information on this transition is discussed in sub-section 4.1.

Other cost of capital parameters – updating of the ROE and long term debt rate, incorporating the deemed short-term debt rate, and implementing the short term debt component in the capital structure – will be implemented when a distributor files a cost-of-service rebasing application.

Having reviewed the cost of capital policy, the Board does not anticipate reviewing this issue again in the context of third generation incentive regulation.

3 Incentive Regulation

Incentive regulation is an alternative to traditional cost of service rate setting. Incentive regulation is intended to provide distributors with the opportunity to increase returns to shareholders through the implementation of efficiency initiatives. These efficiencies are also intended to benefit ratepayers by reducing costs.

This is the second time the Board has adopted an incentive rate setting mechanism for electricity distributors. The first was established in 2000 in the first electricity distribution rate handbook. The Board intends to review this 2nd Generation IRM in the future and determine how a long-term mechanism should be set.

The objective of the 2nd Generation IRM is to provide regulatory certainty to distributors during the Rate Plan as several rate-related studies are carried out. As such, 2nd Generation IRM is a transitional mechanism, and not an end-state in itself. The Board needs to put in place a formulaic rate adjustment method that will return distributors to incentive regulation, without creating any major hardships for them or for their ratepayers. As outlined below, the Board will rebase rates for each of the distributors over a period of three years.

3.1 Term and Starting Base

As indicated in the Board's April 27, 2006 letter announcing this project, the term (up to 3 years) and starting base (2006 rates) for the 2nd Generation IRM have already been established.

Further, **distributors' rates will not be rebased prior to implementing the incentive adjustment for new rates effective May 1, 2007**. The term of 3 years is not for all distributors. Some, whose rates will be rebased in 2008, will have this mechanism in place for one year. Others whose rates are rebased in 2009 will have this mechanism in place for two years, and the remaining distributors will have their rates rebased in 2010. **This mechanism, therefore, will be effective for at most, three years**. The Board is currently consulting with stakeholders on the criteria it should use to determine the Rate Plan groupings (i.e., which distributors will be rebased in which years).

Issues and Options Raised in Consultation

Some stakeholders commented that the 2006 rates were based on 2004 actual data and therefore the 2nd Generation IRM starting base should be adjusted in 2007 for three years (2004 to 2007) and not one year (2006 to 2007). The Board does not believe that it is appropriate to escalate the rates for the 2006 EDR historical year filers to a current test year. The 2006 test year rates were set based either on a historical test year or on a forward forecast year and were determined by the Board to be just and reasonable for 2006.

3.2 Form

The Board deliberated on different forms of incentive regulation extensively in its RP-1999-0034 proceeding which dealt with performance based regulation for electricity distributors, and in its RP-1999-0017 proceeding in response to Union Gas Limited's application for a performance based rate mechanism. Both proceedings resulted in Board adoption of price cap regulation.

Policy and Rationale

The Board will retain a price cap form of adjustment mechanism for electricity distributors. The price cap continues to be a simple approach that will, along with the implementation of mandatory service quality requirements as described below, provide balanced incentives for efficiency improvements and the maintenance of adequate service quality over the course of the 2nd Generation IRM.

With regard to alternative mechanisms, the Board concludes that a revenue cap approach is not appropriate, at this time. Revenue cap plans make distributors indifferent to gains and losses from demand fluctuations; however, they transfer to customers the risk of volume fluctuations, thus contributing to distribution rate uncertainty.

Benchmarking regulation uses information on industry, sub-industry, or peer group cost performance to establish a benchmark price (i.e., rate) for each firm in that group. Benchmarking will also not be applied at this time. The Board believes that the data and modeling requirements necessary to establish a price cap approach within a benchmarking framework are disproportionate to the objective for the transitional 2nd Generation IRM.

Issues and Options Raised in Consultation

There was no general concern raised about a price cap form. However, Dr. Yatchew, the consultant for the Coalition of Large Distributors, made an observation regarding the effectiveness of incentive regulation in general for government-owned utilities. Dr. Yatchew commented that for government-owned distributors it may be appropriate to take political risk into account when calibrating price cap rules and when determining appropriate rates of return. The Board observes that predicting political risk and its implications through economic regulation is challenging, and that more will be learned on the matter as experience is gained with 2nd Generation IRM. The Board continues to believe, as was stated in its RP-1999-0034 Decision with Reasons, that under incentive regulation, a distributor is responsible for making its investments based on prevailing business conditions, and the objectives of its shareholder within the confines of the price cap, and subject to the service quality standards set by the Board.

3.3 Price Escalator

Under cap mechanisms, changes in price indices such as macroeconomic or industry-specific indicators drive allowed changes in output prices for regulated services (i.e., these indices escalate the allowed prices).

Policy and Rationale

The Board will use the Canada Gross Domestic Product Implicit Price Index (GDP-IPI) for final domestic demand as the price escalator. For each year the GDP-IPI for final domestic demand (Series V3840594) will be taken from the Statistics Canada publication for the previous year. The adjustment in rates will be the difference between that number and the GDP-IPI for final domestic demand built into the previous year's rates. There will be no explicit adjustments in 2nd Generation IRM for ROE or debt costs.

Macroeconomic (e.g., national or provincial gross domestic or consumer product indices) or industry-specific indices can be used to proxy inflation in an incentive regulation formula. Staff's consultant, Dr. Lowry, prepared a report for the Board on incentive regulation entitled "Second-Generation Incentive Regulation for Ontario Power Distributors" (PEG Report). A table from that report is reproduced on the next page. The table summarizes a survey of formulas approved in other jurisdictions and shows that the macroeconomic GDP-IPI is the prevalent inflation proxy used by North American regulators for gas and electric utilities.

X FACTORS APPROVED BY NORTH AMERICAN REGULATORS FOR GAS AND ELECTRIC UTILITIES

Industry	Company	Term	Jurisdiction	Acknowledged Productivity Trend	Inflation Measure	Stretch Factor	X-Factor	Comments
Gas distribution	Boston Gas (I)	1997-2003	Massachusetts	0.40%	GDPPI	0.50%	0.50%	
Gas distribution	Boston Gas (II)	2004-2013	Massachusetts	0.58%	GDPPI	0.30%	0.41%	
Gas distribution	Berkshire Gas	2002-2011	Massachusetts	0.40%	GDPPI	1.0%	1.0%	Adopted the productivity study used by Boston Gas I
Gas distribution	Consumers Gas	2000-2002	Ontario	0.63%	CPI	0.50%	1.10%	O&M Productivity
Gas distribution	Union Gas	2001-2003	Ontario	0.9%	GDPPI	0.5%	2.5%	
Gas distribution	San Diego Gas and Electric	1999-2002	California	0.68%	Industry specific	0.55% (Average)	1.23% (Average	
Gas distribution	Southern California Gas	1997-2002	California	0.50%	Industry specific	0.80% (Average)	) 2.30% (Average)	Special 1% factor added to X to reflect declining rate base
Gas distribution	Bay State Gas	2006-2015	Massachusetts	0.58%	GDPPI	0.4%	0.51%	Adopted Boston Gas II
Bundled power service	Pacificorp	1994-1996	California	1.4%	Industry specific	NA	1.4%	Company specific productivity
Power distribution	San Diego Gas and Electric	1999-2002	California	0.92%	Industry specific	0.55% (Average)	1.47% (Average)	
Power distribution	Southern California Edison	1997-2002	California	NA	CPI	0.58% (Average)	1.48% (Average)	0.90% productivity trend estimated by Edison and Commission staff but not formally acknowledged by CPUC
Power distribution	All Ontario distributors	2000-2003	Ontario	0.86%	Industry specific	0.25%	1.5%	Productivity trend referenced is the 10 year average growth rate X factor is based on 5 and 10 year weighted average
Power distribution	Nstar	2006-2012	Massachusetts	NA	GDPPI	NA	0.63% (average)	
Bundled power service	Central Maine Power (I)	1995-1999	Maine	NA	GDPPI	NA	0.9% (average)	
Power distribution	Central Maine Power (II)	2001-2007	Maine	NA	GDPPI	NA	2.57% (average)	
All utilities	**Sample Average**			**0.70%**			**1.21%**	
All industry specific	**Sample Average**						**1.58%**	
All macro-economic	**Sample Average**						**1.01%**	

Source: PEG Report (Table 1, page 55)

The above summary includes the inflation measures used in those jurisdictions. Although a macroeconomic measure, the GDP-IPI is published by a trusted source, is readily available and is likely more easily understood by the public than an industry-specific measure would be.

With regard to use of the Consumer Price Index (CPI) rather than GDP-IPI, the Board agrees with Dr. Lowry that GDP-IPI is preferable to the CPI because it tracks a more relevant set of goods and services used as inputs for production by businesses, including electricity distributors. CPI tracks the prices of consumer goods and services, whereas GDP-IPI is a broader measure of inflation that covers other relevant sectors of the economy such as capital equipment. Therefore, the Board will use the GDP-IPI as the inflation proxy for the 2nd Generation IRM.

The Board employed an industry-specific index (IPI) approach in its first generation incentive mechanism for electricity distributors. As discussed in the PEG Report, an industry-specific input price index tracks industry input price fluctuations better than an economy-wide measure. Therefore, it may better mitigate significant gains and losses that might result from the failure of a macroeconomic index to track industry input price inflation. Both electricity transmission and distribution are capital intensive businesses and are therefore sensitive to changes in the cost of funds. This pattern of fluctuation can differ from that of an economy-wide measure for extended periods. However, the Board is of the view that the GDP-IPI approach is less controversial and easier to implement: only one index needs to be obtained and the only calculation necessary will be the annual change in the index.

Staff considered the following GDP-IPI indices available from Statistics Canada:

- Ontario GDP-IPI;
- Ontario GDP-IPI for final domestic demand;
- Canada GDP-IPI; and
- Canada GDP-IPI for final domestic demand.

Both Ontario indices are available only by late April. Distribution rate adjustments are typically scheduled to be in place May 1st. Therefore, the Ontario GDP-IPI data are not available in time for the Board's distribution rate adjustment process.

Both Canada indices are published for the previous year and 4th quarter by February 28th. This timing is suitable. Of the two national indices, the Board concludes that the Canada GDP-IPI should not be used because it includes consideration of inflation in the prices of crude oil and natural gas, among other price-volatile exports. These are important to Canada as a whole, but such exports are not inputs to "wires-only" electricity distributors in Ontario.

The Canada GDP-IPI for final domestic demand excludes these inputs. Therefore, the Board will use this index (Series V3840594). Further, the year-over-year change in the index will be used to calculate the price escalation. The Board is of the view that this index will result in a fair price adjustment because it better reflects the overall inflation experienced in the economy.

One stakeholder noted that, under staff's proposal, there would be no adjustments for ROE or for changes in distributors' debt costs during 2nd Generation IRM. They commented that while, in theory, GDP-IPI may track cost of capital changes, this would only occur over the long-term and may not be reflective of the electricity distribution industry, which is capital intensive. In response, one consumer group observed that the issue is not easily addressed within a "price-cap" incentive regulation mechanism:

- first, any adjustment to the IRM formula for changes in ROE would require distributor-specific calculations;
- second, it would also require obligating distributors to report any changes in debt costs so they, too, could be factored into the annual adjustment; and
- there would inevitably be some degree of double counting as the GDP-IPI formulation does include some consideration of changes in cost of capital.

However, two stakeholders commented that while the impact should not be material in the short term, this issue needs to be addressed in the longer-term. For 2nd Generation IRM, the Board is satisfied that during the term of the plan changes in GDP-IPI will implicitly recognize changes in the ROE and debt rates, and that therefore no further adjustment will be required.

Issues and Options Raised in Consultation

Some distributors commented that they would support the use of either CPI or GDP-IPI for the purposes of a price escalator in 2nd Generation IRM. However, they expressed concern over the exclusion of escalators related to crude oil and natural gas. Distributors commented that these factors affect many of their costs. In response to this concern, the Board notes that the GDP-IPI for final domestic demand does include these factors. It only excludes oil and gas for export.

One stakeholder supported use of an industry specific input price index and argued that it mitigates the significant gains and losses that result from the failure of a broad economy-wide index (e.g. GDP-IPI) to track changes in industry specific input prices better. However, another stakeholder noted that there is no “available” industry specific index even if the Board wanted to consider one. This stakeholder went on to say that, under the current Electricity RRR, distributors file statistics on performance based regulation related information annually. However, the Board believes that some of the required data may not be available to construct a credible industry specific index. Therefore, as a practical matter, the 2nd Generation IRM must rely on a macroeconomic index.

Staff originally proposed calculating the price escalator based on the change in the level of the GDP-IPI for final domestic demand on a 4th quarter over 4th quarter basis. This would factor year-end adjustments into the index. However, a number of stakeholders calculated that it would be better to base the change in the index on an annual over annual figure to reduce volatility inherent in using the quarter to quarter approach. The Board is persuaded that this is more appropriate.

3.4 X-factor

Under cap mechanisms, the allowed rates of change in the price of the regulated service are generally adjusted by offsets (often called an X-factor). The PEG Report detailed how X-factors based on indexing research typically include consideration of an *input price differential* (may be computed using Canadian input price trends), a *productivity differential* (may be the difference between a proxy for a total factor productivity (TFP) trend of Ontario's power distribution industry and the multi-factor productivity (MFP) trend of the Canadian economy), and a stretch factor.

Policy and Rationale

The Board has determined that distributors will be subject to a 1% X-factor for the duration of the 2nd Generation IRM. The X-factor precedents summarized in the PEG Report (reproduced in sub-section 3.3 above) suggest 1% as a reasonable reflection of relevant input price and acknowledged productivity trends. The Board believes that the Canada GDP-IPI for final domestic demand and 1% X-factor together should reasonably track industry unit costs, including efficiency gains, during 2nd Generation IRM. Therefore, the Board has determined that the value of the X-factor will remain fixed at 1% for the three-year term. Setting the X-factor at 1% over the term of the plan will provide price predictability and greater price stability. It also provides a sharing of the benefit of efficiency gains to ratepayers immediately.

Like the selection of the inflation measure, the selection of the X-factor is, for 2nd Generation IRM, a function of simplicity and transparency. Since 2nd Generation IRM is of a short duration, the Board will not develop an X-factor calibration that attempts to explicitly consider the productivity capabilities of each individual electricity distributor along with a stretch factor. Differentiated X-factors based on individual distributor circumstances would require an examination of distributor-specific evidence. In light of the spectrum of X-factor values put forward by distributors (as low as 0.7%) and consumer groups (as high as 1.2%) below, the Board believes that the 1% X-factor is reasonable for 2nd Generation IRM.

Issues and Options Raised in Consultation

Most distributors commented that 1% is too high and that the value should be based on individual distributor circumstances. They commented that distributors have been under rate freezes for an extended period of time and could not squeeze further efficiencies out of their businesses. Further, they commented that some distributors are experiencing a declining customer base – and suggested that a differential efficiency factor be determined based on growth rate. Some distributors proposed that the value of the X-factor should be 0.7%, stating a conservative approach was appropriate for 2nd Generation IRM – i.e., one without consideration of a stretch factor. The 0.7% was identified as reflective of acknowledged productivity trends without a stretch factor from the PEG Report. It was also argued that there is little reason to conclude that a distributor would be able to react to achieve efficiency savings under an IRM of such a transitional nature and short time period (some distributors will only be subject to it for one year). Therefore the X-factor simply becomes a somewhat subjective rollback of the inflation escalator. The Board does not agree that 1% is too high and that there is no opportunity for improvement in the industry over the next three years. While some distributors will only be subject to 2nd Generation IRM for one year, many will be subject to it for two and three years.

In contrast to distributors' comments that 1% is too high, consumer groups proposed that the value of the X-factor be increased. Skepticism was expressed that efficiency improvements will occur during 2nd Generation IRM given the variable term of the plan and the proposed X-factor of 1%. In one instance, it was argued that 1% is not adequate to bring about efficiency improvements. It was recommended that the X-factor be increased to 1.1% or 1.2% for 2nd Generation IRM. However, it was noted that this value is relatively modest in comparison to the values set by the Board in its previous plans (i.e., 1.5% for electricity distributors using IPI, and 2.5% for one of the gas distributors using GDP-IPI). It was also suggested that setting the X-factor for a longer term plan should include review of an input price differential (subject to the inflation factor used), historical productivity and a stretch factor (in lieu of an earnings sharing mechanism). In another instance, it was proposed that the X-factor value be determined relative to the distributor's current rates, similar to a benchmarking approach.

One stakeholder commented that although the proposed price cap rule does not recognize differential efficiencies across distributors and requires a common efficiency improvement of 1%, the stakeholder anticipated that future refinements would incorporate such differences. The stakeholder acknowledged that the proposed price cap rule comprises an important step in the process of improving regulation of Ontario distributors, describing it as simple and transparent, thereby easing regulatory burden for the regulator and the distributors.

While the Board has considered stakeholders' concerns, the Board is not convinced that for 2nd Generation IRM it is practical or necessary to set the value based on individual distributor circumstances. The 1% X-factor is low enough to recognize that distributors may be under some cost pressures and will be motivated to seek some operational savings over the term of the plan, and it is high enough to provide a benefit to consumers.

3.5 Z-factors

Under cap mechanisms (price or revenue), contingencies need to be built into the regulatory regime to provide the flexibility to recognize extraordinary events outside the control of distributor management. These are called Z-factors. Examples include changes in regulation, changes in accounting or tax rules, and natural disasters.

Policy and Rationale

For 2nd Generation IRM, the Board will limit reliance on Z-factors to well-defined and well-justified cases only – specifically, Z-factors will be limited to changes in tax rules and to natural disasters. The Board believes that for 2nd Generation IRM, Z-factors should be limited to events genuinely external to the regulatory regime and beyond the control of management and the Board – changes in Board policy should not be included. The Board can always assess the implications of such changes and make provision for them. Regardless, in order for amounts to be considered for recovery in a **Z-factor**, the **amounts must satisfy the eligibility criteria set out in Table 3**, below. The Board notes that changes in tax rules may result in positive or negative amounts.

Table 3: Z-Factor Amount Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amount must have been prudently incurred. This means that the distributor's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

In addition, **the Board intends to maintain the materiality thresholds established in the 2006 EDR Handbook**: for expenses, the materiality threshold would be 0.2% of total distribution expenses before taxes; and for capital cost recovery, the materiality threshold would be 0.2% of net fixed assets. In both cases, the materiality threshold must be met on an individual event basis in order to be eligible for potential recovery.

Consistent with guidelines established for the first generation incentive mechanism, the Board has determined that when a distributor applies for disposition of these amounts, it will be required to submit evidence that the amounts which were incurred meet the three criteria outlined above. Appendix C outlines the detailed requirements for Z-factors, and has been adapted from the Board's 2000 Electricity Distribution Rate Handbook.[5] These requirements were established in consultation with stakeholders on the matter of performance-based regulation for electricity distributors (RP-1999-0034).

The Board may review and adjust the amounts claimed under Z-factor treatment during the term of the incentive regulation plan. This will allow the Board and any affected distributor the flexibility to address extraordinary events in a timely manner. The Board is of the view that the operational response to normal events, including winter storms, is within the planning control of management and that distributors are already adequately compensated for the risk of these types of events. Therefore, the Board will expect that any application for a Z-factor will be accompanied by a clear demonstration that the management of the distributor could not have been able to plan and budget for the event.

Issues and Options Raised in Consultation

Most stakeholders acknowledged the need for an IRM plan to provide for Z-factors.

Distributors were generally supportive of the proposed Z-factor requirements. However, some distributors expressed concern that the Board might attempt to exhaustively define when a factor would be available to a distributor, and commented that any list should be illustrative only.

Consumer groups commented that the tests for determining whether Z-factors are appropriate must be clear and set out prior to the commencement of the plan. Specifically that:

- the onus should be on the distributors to justify any Z-factor adjustments;
- the evidence provided in support of a Z-factor application must be thorough and subject to testing by the Board and intervenors prior to approval; and

[5] Revision 1.0, issued on November 3, 2000

- consistent with the 2006 EDR process there should be an onus on the distributors to bring forward Z-factors that may increase the revenue requirement or reduce it – the use of Z-factors must be symmetrical and should not be limited only to cost increases.

The last point was particularly a concern as staff did not recommend inclusion of an earnings sharing mechanism in the incentive regulation framework. Therefore, consumer groups were concerned that an unusual event that results in cost decreases or revenue increases must somehow be brought forward. The Board recognizes these concerns and is of the view that Z-factor adjustment for changes to tax rules should be symmetrical.

The Board has considered stakeholders' concerns and will limit the use and complexity of Z-factors because they undermine the basic principles of incentive regulation as opposed to traditional cost of service regulation. Therefore, only changes in tax rules and natural disasters will be considered.

3.6 Capital Investment under Incentive Regulation

Some distributors expressed concern over aging infrastructure and the need for increased investment in that infrastructure to maintain the appropriate levels of service which may be beyond the level supported by existing rates. They proposed that the incentive regulation formula should allow for the pass through of incremental capital expenditures in consideration for growing capital program costs. This could be done through an additional factor in the price cap formula.

Hydro One Networks Inc.'s consultant, Mr. Todd of Elenchus Research Associates, proposed a factor that would be an incremental percentage to the price cap index, contingent on a distributor filing an asset condition assessment in support of its proposal.

Typically, an incentive regulation mechanism is intended to encompass both capital and operating costs. This increases incentives for operating performance. In a capital intensive business such as electricity distribution, containing capital expenditures is a key to good cost management. The addition of a capital investment factor would mean that incentive under the price cap mechanism would be significantly reduced because the factor would address incremental capital spending separately and outside of the price cap. Further, it would unduly complicate the application, reporting, and monitoring requirements for 2nd Generation IRM because it would require special consideration to be implemented effectively.

The Board concludes that there is no need for a capital investment factor in this 2nd Generation IRM plan. Those distributors with an inordinate capital spending program can be accommodated through rebasing. Distributors should review the Board's letter of December 19, 2006 which deals with the timing of rebasing. Attached to that letter is a discussion paper on a screening methodology to establish a rebasing schedule for electricity distributors, including the option of self nomination.

3.7 Earnings sharing

The Board's policy, as expressed in the Natural Gas Forum Report[6], does not support earnings sharing mechanisms (ESMs). One of the reasons for that policy decision is that ESMs are thought to reduce the distributor's efficiency incentives. Another is that it may increase regulatory burden and retroactive review of a distributor's activities.

While consumer groups generally accepted the Board's policy position on ESMs, they expressed concern that over-earning be addressed in the Board's incentive regulation framework. Also, they commented that ratepayers will not have access to full information regarding a distributor's financial results and will not have the same ability

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[6] *Natural Gas Regulation in Ontario: A Renewed Policy Framework*, March 30, 2005

as distributors to seek Z-factor relief. Accordingly, they argued that the use of an earnings sharing mechanism would provide a level of ratepayer protection during the plan. Others commented that in the absence of an ESM, the Board should require distributors that have excess earnings to rebase first. The Board is not convinced that an ESM is appropriate for 2nd Generation IRM. However, the Board may be informed by a comparison of a distributor's actual regulatory returns with Board-approved levels in the process of determining Rate Plan groupings for rebasing.

3.8 Service Quality

Service quality provisions are an important consideration in incentive regulation plan design. Definitions and reporting requirements of electricity distribution service quality indicators (SQIs) and the minimum standards set for them are laid out in Section 15, entitled Service Quality Regulation (SQR), of the 2006 EDR Handbook. For convenience, the list of the SQIs that distributors are required to measure and report on is provided in Table 4, below.

Table 4: Service Quality Indicators in the Handbook

Customer Service	Service Reliability
Connection of new services Underground cable locates Appointments Telephone accessibility Written response to enquiries Emergency response	System average interruption duration index System average interruption frequency index Customer average interruption duration index

Distributors have been reporting their performance on these indicators since 2000. Reporting is currently made annually of monthly and annual results under the Board's Electricity RRR. Some audits of service quality have been conducted and distributors' performance during the period 2002 to 2004 was reviewed as part of the 2006 EDR applications.

Policy and Rationale

The Board is resuming its SQR review to refine its SQR regime for electricity distributors. The Board is committed to ensuring an effective SQR regime as an integral element of incentive regulation.

In September 2003, the Board initiated a consultative process to review existing electricity SQIs. The process considered changes to these indicators and standards, new appropriate measures, and what, if any regulatory consequences there should be for persistent below-standard performance. While a working group of Board staff, distributors and other stakeholders met until February 2004, the process was not completed.

Issues and Options Raised in Consultations

Several stakeholders expressed concern that the Board's SQR regime be fully operational on commencement of 2^{nd} Generation IRM. It was commented that in any incentive regulation model it is essential to ensure that safety, reliability and quality of service are not degraded during the course of the plan.

Consumer groups urged the Board to make all SQR information publicly available, to more easily and transparently assess adherence to the requirements and allow for comparisons among all of the distributors. They commented that in the absence of full rate proceedings, the public reporting of SQIs is needed to ensure transparency and accountability for performance. Further, they noted that it would help to ensure that distributors do put forward the effort to meet and perhaps even exceed the standards.

One distributor commented that having mandatory and enforceable SQIs and performance requirements in and of itself will not result in improvements in distributors' performance as measured by the SQIs. The distributor argued that addressing this issue as a matter of compliance is contrary to the spirit of incentive regulation which it believes relies more on a cooperative approach that benefits all parties. The distributor suggested that due to the interim nature of 2nd Generation IRM and the fact that SQIs and performance requirements are evolving in response to experience and improvements in data quality and availability, perhaps the Board should focus on this issue as part of a longer-term plan when better data and more precise basis of arriving at differential performance targets can be established.

One stakeholder commented that given that distribution service safety, quality and reliability is what customers are paying for in their distribution rates, it is essential that interested parties have the opportunity to address a distributor's service performance relative to the distributor's proposed rates. Therefore, despite the codification of SQR, it was requested that the Board explicitly recognize the need for service performance to remain within scope in a distributor's rate proceeding.

In light of stakeholders' comments, the Board will resume its SQR review to refine its SQR regime for electricity distributors in consultation with stakeholders. This review will include consideration for public reporting of SQIs.

3.9 Rebasing

The timing of expenditures (i.e., operating, maintenance, replacement capital, etc) that are made periodically is an issue of mounting interest in incentive regulation schemes. Some timing issues may be revealed at rebasing.

The Board is working on details for the 2008, 2009, and 2010 rebasing reviews, as outlined in the Rate Plan. This work includes the following assumptions:

- the rebasing review will be based on a forward test-year cost of service filing;
- benchmarking evidence will be used as an input to the review;
- the benchmarking method may differ from the current comparators and cohorts approach; and

- benchmarking may be applied to the proposed costs in any forward test year as well as to costs in recent historical years.

The proposed requirements for the rebasing reviews are under development.

4 Implementation

4.1 Transition to Recommended Cost of Capital

The cost of capital will be implemented into a distributor's rates in two stages. First, as part of the rate rebasing process that begins in 2008, distributors will have their debt rates and ROEs adjusted in accordance with the policies described in section 2. Second, as part of rate adjustments between 2008 and 2010, distributors will have their capital structure adjusted in accordance with the policies described in section 2 and by the method described below.

Policy and Rationale

The Board will include an adjustment to rates in 2008, 2009, and 2010 as outlined below **to transition distributors from their existing capital structures to the single deemed capital structure**.

The adjustment for capital structure would begin with the 2008 rate year, on the 2006 approved rate base, unless a new rate base has been approved by the Board. As summarized in Table 5, below, the adjustment will be based on the following schedule:

- For distributors starting at equity of 35%, the equity component will move in equal increments over 2 years until it reached 40%;
- For distributors starting at equity of 45%, the equity component will move in equal increments over 2 years until it reached 40%; and
- For distributors starting at equity of 50%, the equity component will move in equal increments over 3 years until it reached 40%.

Table 5: Transition to Target Capital Structure

			Deemed Equity Component		
Current Deemed Equity	Variance from Target Equity of 40%	Transition Period (years)	2008	2009	2010
35%	5%	2.00	37.5%	40.0%	
45%	-5%	2.00	42.5%	40.0%	
50%	-10%	3.00	46.7%	43.3%	40.0%

4.2 How rate adjustments will be made using the incentive mechanism

Figure 1, below, summarizes what is in and what is not in electricity distribution rates based on 2006 rate orders. The block on the left shows what is in distribution rates and the right-side denotes items that are not.

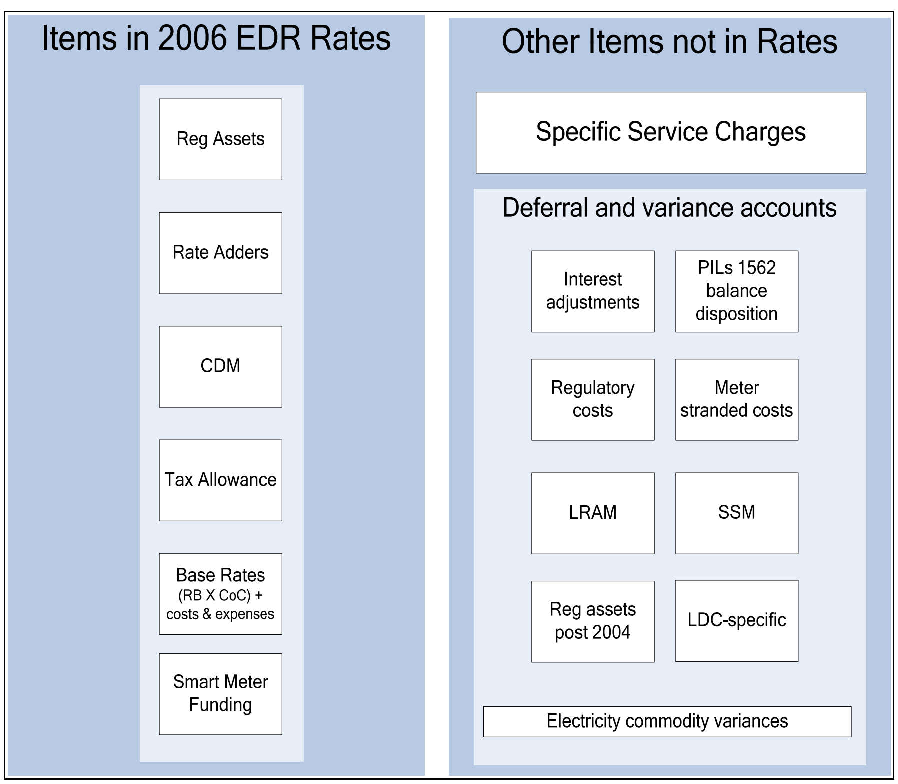

Figure 1: What's In and What's Outside of Electricity Distribution Rates

4.2.1 Allowance for Smart Meter Implementation

An amount was added in 2006 rates for smart meter implementation in order to provide "seed money" to distributors for their investment requirements and to help smooth rate shock to consumers.

Many parties expressed concern that further consideration be given to anticipated growth in smart meter costs to distributors. The Board has communicated separately to distributors that the process for approval of additional requirements for funds related to smart meters is under review, and will be dealt with shortly. The Board will advise parties of how changes will be implemented.

4.2.2 Conservation and Demand Management (CDM)

Recently, the Board issued a letter to distributors advising them that they may apply to the Board for incremental CDM funding through distribution rates. CDM-related costs which are to be recovered through distribution rates (i.e., any new spending on CDM, revenues from recovery of a lost revenue adjustment claim, or a shared savings claim) will be dealt with separately from the 2nd Generation IRM rate adjustment. Should the Board provide for a more comprehensive revenue stabilization mechanism for distributors, then it may consider how the reduced risk might be reflected in the Board's determination of an appropriate cost of capital.

4.2.3 Treatment of Taxes

A distributor's allowance for taxes (whether PILs or actual taxes) currently includes provision for income tax, Ontario capital tax, and large corporation tax.

The Board considered whether only the income tax portion of taxes should be subject to the price cap index. The large corporation tax was repealed retroactive to January 1, 2006; however, it remains in 2006 rates. The allowance for Ontario capital tax is relatively small compared to the allowance for income tax and therefore need not be shielded from the index.

The Board has determined that the large corporation tax, which was repealed with effect from January 1, 2006, will be removed from base rates in 2007. All other taxes will be adjusted under the price cap index.

4.2.4 Deferral and Variance Accounts

Deferral and variance account balances will be dealt with in accordance with the provisions of the *Ontario Energy Board Act, 1998*.

Consistent with its proposal on Z-factors, the Board has determined that, to the extent possible, it will limit reliance on creation of new deferral accounts during the term of the scheme to well-defined and well-justified cases only. Z-factor rules should govern need for, and treatment of deferral accounts.

4.2.5 Application of the Price Cap Index

The Board will apply the price cap index uniformly across all customer classes and to both the monthly service charge and volumetric rate, including taxes. Also, the adjustment for 2007 rates will be based on the approved 2006 information. This will require a standardized and simple application to be filed by distributors.

The index will not be applied to specific service charges as the Board recently completed a generic review of these charges.

There are a number of components to distribution rates to which the index will not be applied. This includes the current smart meter amount, regulatory assets amounts, rate adders, and CDM amounts. The current smart meter amount may be affected by the on-going review that the Board is engaged in to determine how smart meter funding should be provided.

This “de-construction” of 2006 rates is conceptually illustrated in Figure 2, below.

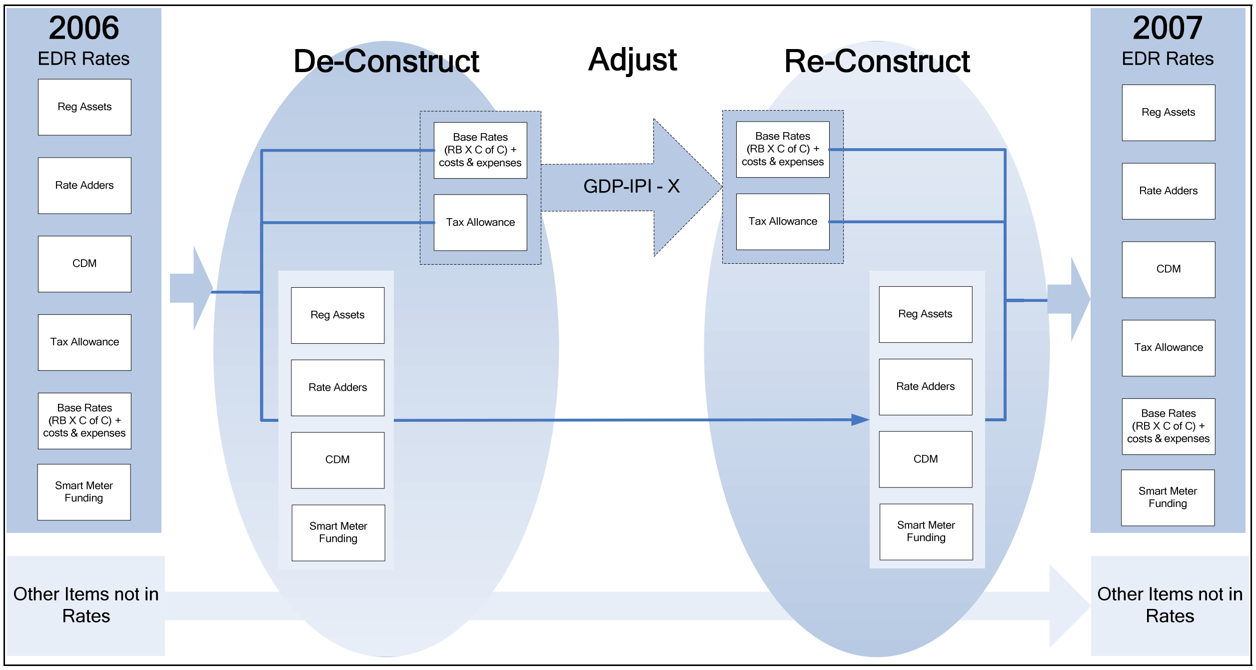

Figure 2: Conceptual Diagram of 2007 Rate Adjustments

The practical implementation of this approach using the 2006 rates as a point of departure may mean that some of this de-construction could occur at the base revenue requirement level. Regardless, the resultant monthly service charge and volumetric rate (both including taxes) for all customer classes will have been adjusted uniformly by the price cap index amount. That is, if the price cap index is 1%, then the index will be applied so that the rates, including taxes, will all be adjusted upwards by 1%.

After adjusting the base rates and taxes with the price cap index, rate elements would be “re-constructed” to derive 2007 rates.

As discussed above, the adjustment for capital structure would begin with the 2008 rate year.

4.3 Off-ramps

The Board expects distributors to use the incentive mechanism to file a rate application as required over the three-year period to effect rate adjustments in 2007, 2008, and 2009. As noted previously, there are limited adjustments available to distributors. If these adjustments are insufficient for specific cost pressures (e.g., additional capital investment) or the distributor is in the tranche to be rebased, then the Board would expect these distributors to file a comprehensive cost of service application and not to rely on the simplified filing requirements for the incentive mechanism.

5 Summary

The Board engaged many interested stakeholders in the discussion of an appropriate cost of capital and 2nd Generation IRM for electricity distributors. This consultation aided the Board in developing the policies detailed in this report. The Board has appreciated the input from all stakeholders in determining the approach it should take.

5.1 Cost of Capital

The cost of capital policy will remain in effect until it is reviewed and changed by the Board. The cost of capital elements are summarized in the following table.

Table 6: Components of the Board's Cost of Capital Policy

Capital structure	• One structure – 60% debt and 40% equity. • Move to this structure equally: 2 yr period for distributors closing a 5% gap; and a 3 yr period for those closing a 10% gap. Start in 2008, finish by 2010.
Debt structure	• One structure to include short-term debt and long-term debt: deemed short-term debt percentage of rate base based on average of distributors; and long-term debt is difference between 60% and short-term debt. Short-term debt amount is 4%. Long-term debt amount is 56%.
Equity structure	• One structure to include common equity of 40%.
Short-term debt rate	• Short-term rate is the average of the 3-month Bankers' acceptance rate over the weeks of the same month as is used for estimating long-term debt rates and the ROE, plus a spread of 25 basis points.
Long-term debt rate	• Existing debt that is either affiliate or third party will be unchanged from the Board approved values. • New third party debt – at the rate prudently negotiated by the distributor with the financing company. • New affiliate debt – lower of the contracted rate or the updated deemed debt rate. Updated deemed rate is consensus forecast plus the premium of A/BBB bonds. Premium is difference of average A/BBB Long-term Corporate Bond yield from long Canada Bond yield.
Common equity return	• No change to current ROE method – modified CAPM method which includes a consensus forecast rate plus an equity risk premium. This includes an implicit 50 basis points for transactional costs.

5.2 Price Cap Incentive Regulation

This 2nd Generation IRM policy will remain in effect until its final application in the 2009 rate year. The rate adjustments for the 2007 rate year will apply to all distributors. For the 2008 rate year the policy will apply to distributors that do not apply for rebasing. For the 2009 rate year it will apply to those remaining distributors that have not yet applied for, or been subject to, rebasing. The mechanism elements are summarized in the following table.

Table 7: Components of the Board's 2nd Generation Incentive Regulation Mechanism Policy

Price Escalator	• Canada GDP-IPI for final domestic demand – updated annually.
X factor	• Fixed at one percent per year for term of plan – all distributors subject to the same value.
Z-factors	• Will be limited to changes in tax rules and to natural disasters, and based on the three criteria of causation, materiality and prudence.

Appendix A: Method to Update the Deemed Long-term Debt Rate

The Board will use the Long Canada Bond Forecast plus an average spread with "A/BBB" rated corporate bond yields to determine the updated deemed debt rate.

The following approach is consistent with the ROE method. As per the approach adopted in the 2006 EDRH, the ROE and the long-term debt rates are based on the same risk-free rate forecast. Therefore, they differ only through the risk premiums that reflect their distinct natures and for which lenders/investors seek commensurate returns. This approach simplifies the calculations and aims to make it easier to understand the numbers. Specifically, the Long Canada Bond Forecast ($LCBF_t$) used will be the same as that used for updating the ROE. The average spread between "A/BBB" rated corporate bond yields and 30-year (long) Government of Canada Bond yields will be calculated as the average spread over the weeks of the month corresponding to the Consensus Forecasts.

The deemed Long-Term Debt Rate ($LTDR_t$) will be calculated as follows:

$$LTDR_t = LCBF_t + \frac{\sum_w (CorpBonds_{w,t} - {}_{30}CB_{w,t})}{n}$$

Where:

- $CorpBonds_{w,t}$ is the average long-term corporate bond yield from Scotia Capital Inc. for week w of period t [Series V121761];
- ${}_{30}CB_{w,t}$ is the 30-year (long) Government of Canada bond yield for week w of period t [Series V121791]; and
- n is the number of weeks in the month for which data are reported.

Appendix B: Method to Update ROE

ROE Update for any Period

Using March 1999 as the starting calculation and substituting for the initial ROE and Long Canada Bond Forecast approved by the Board in the Decision RP-1998-0001 the following is the adjustment formula for calculating the ROE at time *t*:

$$ROE_t = 9.35\% \; + 0.75 \times (LCBF_t - 5.50\%)$$

The ROE must be set in advance of the approved rates. The final ROE will be factored into rates using the Long Canada Bond Forecast based on *Consensus Forecasts* (as detailed below) and Bank of Canada data three months in advance of the effective date for the rate change. Therefore, for May 1 rate changes, the ROE will be based on January data – effectively *Consensus Forecasts* published during that month and Bank of Canada data for all business days during the month of January. The necessary data is available within the first or second business days after the end of the month and thus poses no delay for determining rates.

Long Canada Bond Forecast for any Period

For any period *t* the Long Canada Bond Forecast $LCBF_t$ can be expressed as:

$$LCBF_t = \left[\frac{{}_{10}CBF_{3,t} + {}_{10}CBF_{12,t}}{2}\right] + \frac{\sum_i ({}_{30}CB_{i,t} - {}_{10}CB_{i,t})}{I_t}$$

Where:

- ${}_{10}CBF_{3,t}$ is the 3-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time *t*;

- ${}_{10}CBF_{12,t}$ is the 12-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time *t*;
- ${}_{30}CB_{i,t}$ is the actual rate for the 30-year Government of Canada bond yield at the close of day *i* (as published by the Bank of Canada) [Series V39056] during the month (this is the previous month data, the same as used for updating the ROE for natural gas distribution) corresponding to time *t*;
- ${}_{10}CB_{i,t}$ is the actual rate for the 10-year Government of Canada bond yield at the close of day *i* (as published by the Bank of Canada) [Series V39055] during the month corresponding to time *t*; and
- I_t is the number of business days for which published 10- and 30- Government of Canada bond yields are published during the month corresponding to time *t*.

Appendix C: Z-Factors

A Z-factor has been incorporated into the incentive regulation mechanism for well-defined and well-justified cases only – specifically, Z-factors will be limited to changes in tax rules and to natural disasters. These events are generally not within management's control. However, options are sometimes available for how management responds, each with various tradeoffs between cost and effectiveness. The distributor will be required to supply the details of management's plans for addressing these events in support of the distributor's request for special cost recovery. The Board may limit the recovery of certain amounts associated with activities.

A distributor may record amounts which meet the eligibility criteria presented below for Z-factor events.

A distributor must follow the requirements listed below to be eligible to apply to the Board to claim any amounts into rates which the distributor has recorded.

Eligibility Criteria for Z-factor Amounts

In order for amounts to be considered for recovery in the Z-factor, the amounts must satisfy all three tests set out in the following table.

Table 8: Z-Factor Amount Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amount must have been prudently incurred. This means that the distributor's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

The above three criteria will be applied to determine the eligibility of amounts for recovery through Z-factors, or any other approach deemed appropriate as a result of Board review. It should be noted that when an electricity distributor does apply for disposition of these amounts, it will be expected to submit evidence that the costs/revenues which were incurred/received meet the three standards outlined below in its annual application.

Causation

For Z-factor amounts, the revenue or expense must be clearly outside of the base upon which rates were derived.

Materiality

Recovery is reserved for amounts which have a significant influence on the operation of the distributor. As a guideline, an expense will be considered material if it involves 0.2% of total distribution expenses before taxes; and a capital cost will be considered material if it involves 0.2% of net fixed assets. Therefore, materiality will differ depending on the size of the distributor. Further, in both cases, the materiality threshold must be met on an individual event basis in order to be eligible for potential recovery.

Prudence

In supporting the prudence of the expense, the distributor will need to justify the reasonableness of the amount relative to other options that the distributor may have had. For example, if the distributor must incur costs to deal with a natural disaster the amount incurred must be justified.

Board Review

The Board may review and adjust the amounts claimed under Z-factor treatment at any time during the term of the incentive regulation plan.

Balancing Account

Those amounts that pass the three-part test outlined above should be included in account 1572, "Extraordinary Event Costs" of the Board's Uniform System of Accounts contained in the Accounting Procedures Handbook.

Interest on these deferral accounts shall be separately recorded within these accounts. The interest shall be calculated on the monthly opening balances in these accounts at the rate set in accordance with the Board-approved method for accounting interest rates (i.e. short-term carrying cost treatment) for variance and deferral accounts.

In support of a rate adjustment related to Z-factor amounts, the distributor must indicate the amounts booked to these accounts in the previous year and provide evidence that these amounts satisfy the three criteria listed above. Distributors must also propose a disposition amount for these accounts. The distributor must also provide the basis upon which the disposition amount should be allocated to each rate class, including a discussion of the merits of alternative allocations considered. The disposition amounts allocated to each rate class from the deferral account should then be tallied, and a rate class specific revenue requirement adjustment determined.

Disposition Account

The size of the prospective rate adjustment will not be subject to a predefined limit. The absence of a predefined disposition limit will give individual distributors the flexibility to propose the rate rider with due consideration to other rate-related customer impacts.

The Board may either, adjust the class-specific rate adjustments directly based on the information provided, or may seek additional information from the distributor and/or may request a review and report from the Board's Chief Regulatory Auditor on cost eligibility and the derivation of the rate rider.

Appendix D: Filing Requirements for 2007 Rate Adjustments

These filing requirements set out the Board's expectations only for filings by distributors that are applying for rates on the basis of the cost of capital and 2nd Generation IRM policies as set out in this report. Distributors that do not file on this basis will need to file on the basis of the Board's Filing Requirements for Transmission and Distribution Applications in relation to electricity transmission and distribution companies' cost of service rate applications, based on a forward test year.

The implementation of the cost of capital and 2nd generation incentive regulation mechanism policies will occur first with rate adjustments scheduled for May 1, 2007. The 2007 rate adjustments will include:

- the 2nd Generation IRM price cap index adjustment; and
- the removal of the Large Corporation Tax Allowance (for those distributors previously subject to this tax).

The price cap index adjustment will be applied to distribution rates (fixed and variable) net of the Smart Meter Funding increment, Large Corporation Tax Allowance, and incremental 2006 CDM funding. The adjustment will not apply to the regulatory assets rate rider or to Specific Service Charges. While the smart meter funding will continue unadjusted in rates, the Large Corporation Tax and the approved incremental 2006 CDM funding will be removed from rates.

A model (the "IRM Model") has been developed to be used by distributors in applying for rate adjustments. The IRM Model is based on the 2006 EDR Model and is available for downloading from the Board's website. Distributors will be required to make a number of data entries from their approved 2006 EDR Model, including the complete approved 2006 EDR tariff schedule. The steps are detailed below.

2006 EDR Tariff Sheet as Approved by the Board

All distributors must enter all approved 2006 rates. Distributors must also input the 2006 Smart Meter Funding increment that was added to their Monthly Service Charge.

Large Corporation Tax Allowance

For those distributors that had a Large Corporation Tax (LCT) allowance approved in their 2006 distribution rates, the model will reduce rates to reflect the removal of this allowance in 2007. These distributors must input their 2006 approved LCT allowance from their EDR models and 2006 base revenue requirement from the EDR model. The reduction in the allowance will be reflected through a percentage decrease in distribution rates calculated by the ratio of 2006 LCT allowance to the 2006 Base revenue requirement.

The LCT allowance will be removed from 2006 rates before the price cap adjustment is applied.

Incremental Approved 2006 CDM Funding

2006 CDM funding approved in rates for 2006 will be removed from rates before the price cap adjustment is applied. This adjustment does not apply to funds approved under the third tranche of the Market Adjusted Revenue Requirement approved in rates in 2005.

Price Cap Adjustment

Distribution rates are to be adjusted under the 2nd Generation IRM plan each year for two factors: a price escalator and an X factor. In addition, beginning in 2008, the price cap formula will also include an adjustment for the transition to the common deemed capital structure for rate-setting purposes.

The Board has determined that GDP-IPI – for final domestic demand is to be used as the price escalator for the 2nd Generation IRM. The Board expects applicants to use, as a proxy, the current value of 1.92% in their applications. The IRM Model will include this proxy as a reasonable estimate of the index result. When the final 2006 data are published by Statistics Canada in late February 2007, the Board will adjust the inflation index in each distributor's rate application model, to ensure this final published number is used to adjust rates for all distributors.

The X-Factor will then be applied to reduce the upward adjustment resulting from the GDP-IPI value.

The IRM Model will apply the price cap adjustment to fixed and variable distribution rates net of the 2006 smart meter funding increment, Large Corporation Tax allowance, incremental 2006 CDM funding. Further, the price cap will not apply to rate riders or Specific Service Charges.

The Smart Meter Adder

Smart Meter Funding is currently included in the Monthly Service Charge for Metered Customers in accordance with the Board's Decision RP-2005-0020/EB-2005-0529 and as approved in the Board's Decision and Rate Order for each distributor's distribution rate application. The current rate adder will be removed and then re-incorporated into the 2007 rate. The amount of the rate adder may change as a result of the Board's current review of smart meter funding. This will be communicated before the end of January, 2007.

When all adjustments are complete, the IRM Model will generate a new 2007 distribution tariff sheet for the utility that will accompany the Board's decision for each distributor.

Bill Impacts

The IRM Model will include a bill impact analysis, which will provide bill impacts of the distribution rate change only. This analysis is similar to that used in assessing rate applications in recent years.

The Board acknowledges that RPP prices could also change on May 1, 2007 and therefore the IRM Model will include an additional bill impact analysis that will be used when any RPP change is released, expected to be in mid-April 2007.

Manager's Summary

Each application should include a completed IRM Model and a brief Manager's Summary explaining all rate adjustments applied for.

Enbridge Gas Distribution Inc., 2007 Rates, Decision with Reasons – Phase 1, EB-2006-0034

Ontario Energy Board

Commission de l’énergie de l’Ontario

EB-2006-0034

IN THE MATTER OF AN APPLICATION BY:

ENBRIDGE GAS DISTRIBUTION INC.

2007 RATES

DECISION WITH REASONS – PHASE 1

July 5, 2007

Summary of the Decision with Reasons[1]
(EB-2006-0034)

Application	Board Decision
• Degree Day Forecast Methodology	• Approved for each service region, as per amended proposal
• Average Use per Customer	• Approved, to be amended for approved degree day forecast
• General Service and Contract Sales	• Approved, to be amended for approved degree day forecast
• Fuel Switching program expenditures	• Expenditure levels to be managed by Enbridge but must meet Total Resource Cost test
• Energy Link program	• Not approved. Cease program • Recovery of costs incurred
• Gas Supply Risk Management program	• Not approved. Cease program • Recovery of $0.691 million
• 2007 Open Bill Access Deferral account • 2006 Electric Program Earnings Sharing Deferral Account • 2006 Unbundled Rate Implementation Cost Deferral Account • 2006 Alliance Vector Appeal Costs Deferral Account • 2005 and 2006 Gas Distribution Access Rule Deferral Accounts	• Approved as proposed • Approved as proposed • Approved as proposed • Approved as proposed • Approved as proposed
• 38% Equity Component of Capital Structure	• Increase equity component from 35% to 36%
• Revenue to Cost Ratios	• Approved as proposed
• Access to Bill envelope to include inserts by third parties	• Approved with changes
• Rate Implementation	• Recovery of approved revenue deficiency/new rates effective January 1, 2007

[1] This summary (i) excludes the particulars in the 2007 Settlement Proposal and (ii) does not form part of the Decision nor does it itemize all findings and is not to be relied on for the purpose of applying or interpreting the Decision.

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Appendices

EB-2006-0034

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2007.

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION WITH REASONS

JULY 5, 2007

INTRODUCTION

The Application

Enbridge Gas Distribution Inc. ("Enbridge", or "the Company") filed an application dated August 25, 2006 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998*; S.O. c.15, Schedule B, for an order or orders approving or fixing just and reasonable rates for the sale, distribution, transmission, and storage of gas for Enbridge's 2007 fiscal year commencing January 1, 2007 ("2007 test year" or "test year"). The Board assigned file number EB-2006-0034 to the Application.

Appendix A contains details regarding some of the procedural aspects of the rates Application, including a list of witnesses and a list of participants.

The Settlement Proposal

On January 24, 2007, a Settlement Proposal was filed with the Board. During the course of the oral hearing, the parties to the Proposal filed four appendices regarding supplemental completely or incompletely settled items, one regarding issue 6.3, and three regarding issues 7.1 through 7.5. They are included as Appendices C to F of the Settlement Proposal. Appendices C and D are dated February 12, 2007, Appendix E is dated February 20, 2006, and Appendix F is dated March 21, 2007.

A copy of the Settlement Proposal, including the addenda, is attached as Appendix B.

Of the 47 issues on the Issues List, the Settlement Proposal includes the complete settlement of 30 issues and indicated that parties would not address these issues at the hearing. There were 7 issues for which there was a partial settlement, and the parties were unable to reach agreement on the remaining 10 issues.

Below is a list of issues which are presented in the Settlement Proposal as having been completely settled. The Board accepts the cost consequences of the Settlement Proposal and will not review these issues in this Decision.

Issue 1.1	Appropriateness of the Proposed 2007 Rate Base Amounts
Issue 1.3	2007 Safety & Integrity Project Budget Amounts
Issue 1.4	Board Method of dealing with Leave to Construct Applications in Separate Proceedings
Issue 1.5	Meeting requirements of the Board for Independent Cost Benchmark Study for the EnVision Project
Issue 1.6	Appropriate levels of Cost and Benefits for EnVision Project, and how are they to be reflected in rates
Issue 1.7	Justification of total Project Amount of $133 million for Automatic Meter Reading (“AMR”) Project
Issue 1.8	Appropriateness of proposed recovery amount of AMR in 2007 Rates
Issue 2.1	Appropriateness of 2007 Transactional Services Revenue and Sharing Mechanism from 2006 Decision
Issue 2.2	2007 Other Revenue Forecast
Issue 3.1	Gas Cost Forecast and Reference Price
Issue 3.5	Human Resources Costs
Issue 3.7	Corporate Cost Allocation for 2007
Issue 3.8	Regulatory and OEB Related Costs for 2007
Issue 3.9	Decision to Change to December 31 Taxation Year
Issue 3.11	Change in Depreciation Rates for 2007
Issue 3.14	Amounts included in Rates for Capital and Property Taxes
Issue 3.15	Amounts in Rates and methodology for Income Taxes
Issue 4.1	Appropriate Return on Equity for the 2007 Test year

Issue 5.1	Appropriateness of Cost Allocation based on Board Approved Methodology
Issue 5.2	Level of Recovery of Amounts for Demand Side Management Costs in Delivery Charges
Issue 6.1	Delivery Demand Charges
Issue 6.3	Rate Handbook Contents
Issue 6.4	Treatment of Bundled Transportation Charges and T-service Credit
Issue 7.1	Customer Care/CIS – has Enbridge complied with the direction in EB-2005-0001
Issue 7.2	Customer Care/CIS - Actions or Decisions required to prevent duplicated items in Regulatory Asset Account
Issue 7.3	CIS – Appropriateness of Forecast Costs
Issue 7.4	Customer Care/CIS-Appropriate Costs
Issue 8.1	Actions necessary to appropriately reflect the impact of the Decisions of the NGEIR (EB-2005-0551) Proceeding
Issue 8.2	Actions necessary to appropriately reflect the impact of the Decisions of the DSM (EB-2006-0021) Proceeding
Issue 9.2	Setting of Interim Rates, effective January 1, 2007

This Decision with Reasons will address the non-settled issues under the following chapters:

- Forecast of Degree Days
- Average Use-Per-Customer
- Contract Gas Volume and Revenue Forecast
- General Service Volume and Revenue Forecast

- Fuel Switching
- EnergyLink Program
- Open Bill Access
- Risk Management Program
- Deferral and Variance Accounts
- Capital Structure and Cost of Capital
- Revenue to Cost Ratios
- Rate Implementation

On April 16, 2007, the Board issued Procedural Order No. 8, dealing with the settlement of Issue 3.6 (Regulatory Cost Allocation Methodology). Parties had indicated in the settlement that they were unable to reach a settlement on Issue 3.6. The Board ordered that Issue 3.6 will be considered as part of a separate phase (Phase 2), and consequently, Issue 3.6 is not addressed in this Decision. The ultimate resolution of this issue will not affect 2007 rates.

Interim Rate Order of March 26, 2007

The Settlement Proposal included the agreement from all parties that:

> … for rate implementation purposes only, the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. GEC's and Pollution Probe's agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result of Issue 3.2. Schools' agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result of Issue 9.1. (Ex.N1 Tab1 Schedule 1 p9 /filed January 24, 2007)

An Interim Rate Order was issued on March 26, 2007 and is attached as Appendix C to this Decision.

Submissions and exhibits

Copies of the evidence, exhibits, arguments, and transcripts of the proceeding are available for review at the Board's offices.

The Board has summarized the record of the proceeding only to the extent necessary to provide context to its findings.

FORECAST OF DEGREE DAYS

The forecasting of degree days establishes the basis on which the Company can project its expected revenues and from that derive its projected sufficiency or deficiency.

Issue 2.3 reads "Is the forecast of degree days appropriate?"

The Company originally proposed to use the Central region degree day forecast of 3,617 degree days based on the 20-Year Trend method. In addition to the Central region application this forecasting methodology would apply to both Niagara and Eastern regions. The use of this forecast methodology would result in a revenue deficiency of $12.9 million, compared to the last Board-approved degree day forecast.

In its argument–in-chief, the Company amended its proposal by requesting approval of separate forecasting methodologies and forecasts for its Niagara and Eastern regions.

The nine methods evaluated by the Company are: the Naïve method, 10-Year moving average method, 20-Year moving average method, 30-Year moving average method, 50/50 method[2], de Bever method[3], de Bever with Trend method[4], 20-Year Trend method and the Energy Probe method[5]. The Company compared the actual degree days with the forecast degree days for each methodology for each year for the 1990 to 2005 period. The Company then ranked these methods using the following measures: Accuracy (as represented by Mean Absolute Percent Error and Root Mean Square Percent Error), Symmetry (as represented by Mean Percent Error and Percent Over-Forecast) and Stability (as represented by Standard Deviation).

[2] Also referred to as the Union method, is a weighted average of the 20-Year Trend method and the 30 Year Average.
[3] "The de Bever [method] is a regression model and features a long-term and short-term component. The former takes the form of a constant, while the latter is accomplished via a five-year weighted average of degree days (lagged two years). The model is estimated over a period equal to the estimated periodicity of the weather cycle". C2/T4/S1
[4] "The de Bever with Trend [method], as the name implies, adds a trend variable to the previously approved de Bever method". C2/T4/S1
[5] "Energy Probe [method] adds both a trend and a five-year simple moving average to the basic de Bever model". C2/T4/S1

Based on its review, the Company now proposes to use a mix of degree day forecast methodologies. The Company argues that its analysis indicates that it is appropriate to move away from using the de Bever methodology and in its place the Board should adopt the method that is best suited to each of its three regions. Accordingly, the Company is requesting approval for the 20-Year Trend method (and forecast of 3,617 degree days in the Central region), the Energy Probe method (and forecast of 4,410 degree days) in the Eastern region and the 50/50 method (and forecast of 3,546 degree days) in the Niagara region. This new proposal reduces the revenue deficiency related to weather from $12.9 million to $11.7 million.

While intervenors and Board Staff have raised a number of issues with the Company's proposal, the majority of the discussion has focused on the proposed use of the 20-Year Trend method in the Central region.

The Company argues that the current Board-approved method, which was approved in 1990, is no longer appropriate to accurately predict an increasingly volatile and downward trend in heating season degree days.

The Company presented evidence to support its claim that, in recent years, weather has become increasingly volatile and exhibits a warming trend. The Company also presented detailed empirical evidence based on its examination of the different methods. Its analysis, the Company argued, clearly indicates that the 20-Year Trend method produces better forecasts than any of the other methods for the Central region.

Schools and CCC argued that the Company has not made a case sufficient for the Board to adopt a new methodology, particularly a complex mix of various approaches. While Schools accepted the use of a linear trend to forecast degree days, it raised a number of issues with respect to the methods tested, the design of the ranking system, and the length of the test period. Schools also argued that the Board should adopt an interim solution and the issues of weather risk and degree day forecasts should be addressed in a generic proceeding.

CCC submitted that Enbridge has not demonstrated that the 20-year trend is a sufficiently robust and flexible model and that the Board should continue with the de Bever methodology, or set the 2007 degree day forecast using the methodology approved by the Board for Union Gas.

IGUA argued that the Company should not be allowed to change its degree day methodology before the results of the Board's pending weather normalization review are known. IGUA argued that Enbridge's forecast should be determined based on the methodology currently embedded in its rates. IGUA characterized this methodology as the "adjusted" de Bever methodology and it consists of reducing the forecast produced by an application of the Board approved de Bever methodology by 43 degree-days. Accordingly, IGUA argued the 2007 degree day forecast should be 3,805 degree days.

Board Staff identified certain concerns with the Company's proposed methodology, but did not advocate the use of any one particular method.

Energy Probe supported the Company's proposal to use the best performing method in the three regions. However, it argued that the analysis used to assess the performance of the different methodologies, is flawed. Energy Probe submitted that the Board should approve the Energy Probe methodology for the Central and Eastern regions and the 10-year moving average methodology for the Niagara region.

Board Findings

The Board considers the following to be the two issues to be considered with respect to the proposed change in methodology: Has the Company made a sufficient case to alter the currently used methodology? If it has, then what is the appropriate degree-day forecasting methodology (or methodologies) for setting test year rates? The Board deals with each question below.

Has the Company made a sufficient case to alter the currently used methodology?

CCC submits that Enbridge has not made a case sufficient for the Board to adopt a new methodology, particularly a complex mix of various approaches. Schools argues that the Board has an approved degree day forecasting method for Enbridge which was established after a thorough debate with expert evidence and that, from a strict legal point of view, the de Bever method is the default method; since the Company has not met the onus to supplant it, the de Bever method should be used. IGUA, supported by VECC, argues that pending the results of the weather normalization review, Enbridge's forecast should be determined based on the methodology currently embedded in its rates.

The Company argues that it has presented detailed evidence to indicate that the current method is no longer appropriate and notes that those are sufficient grounds to warrant a change in methodology. In response to IGUA's arguments, the Company argues that no such methodology has ever been presented or approved by the Board. The Company further argues that in the years since 2003 the degree day forecasts have been settled and are not premised in any degree day forecasting methodology.

The Board notes that the settlement agreement in the last rates case for the Company (EB-2005-0001) does not make any specific characterization nor does it explain the basis for the degree day adjustment agreed to by the parties from the level proposed by the Company. It merely notes that the parties have agreed to reduce the degree day forecast by 43 degree days. The Board considers the adjustment to be the result of a negotiated settlement rather than being underpinned by any scientific or statistical reasons.

The Board believes that given that the sole purpose of a forecasting methodology is to accurately forecast weather it is simply appropriate to select a method based on the empirical findings.

In the Boards view, the aforementioned evaluation of nine various methodologies presented by the Company reasonably demonstrates that the de Bever method has not produced the most accurate forecasts compared to other methods.

What is the appropriate degree-day forecasting methodology (or methodologies) for setting test year rates?

Having found that the utility has made a compelling case to consider a change in methodology, the Board then must make a determination on an appropriate degree day forecasting methodology.

The Company has presented historical weather data and argues that this data reveals that weather is increasingly volatile and displays a warming trend, especially in the Central region. The Central region is particularly relevant in this context, because it accounts for over 80% of the Company's volumes.

The Board is satisfied that the historical weather data presented by the Company can be interpreted to support the premise that an underlying warming trend and increasing volatility in weather does exist. However, the Board does not find this to be determinative in the selection of the most appropriate model. The Company has presented various methods. Some of these are based on simple moving averages, while others are more sophisticated.

Based on the evidence and arguments, the Board concludes that a linear trend method is an appropriate method to be used. The moving average methods, while they do capture the trend, exhibit a considerable lag, thus making it an inferior method to the linear method. While the Naïve method captures the randomness in the data, it can result in an abrupt and substantial change, which could lead to rate shock. The de Bever method, as noted earlier also has its limitations.

The selection of the trend is a critical factor in the determination of an appropriate forecast. The evidence the Company has presented indicates that a linear regression trend based on 20 years of data, compared to the other eight commonly used methods, generates forecasts that display greater accuracy. for the Central Region having accepted the analysis presented by the Company as part of its review of the nine comparable methodologies, the Board accepts the Company's amended proposal to apply the 20-Year Trend method in the Central region, the Energy Probe method in the Eastern region and the 50/50 method in the Niagara region.

AVERAGE USE-PER-CUSTOMER

This section addresses Issue 2.4, namely, Are the average use-per-customer forecasts for Rate class 1 and Rate class 6 appropriate?

A key element in the Company's forecast of its General Service sales volumes for the 2007 test year is the forecasted average use for Rate 1 and Rate 6 customers. The Company indicated that the models it employs to forecast average use have been in use since 2001 and that, during that period, parties and the Board have accepted these models through the Board-approved Settlement Proposals. Excepting the years 2001 and 2005, in which there were high and volatile gas prices, the average error variances between normalized actual use and Board-approved was less than 1%, indicative of the model's accuracy and validity.

The Company's 2007 forecast of volumes for general service customers was prepared in the spring of 2006, incorporating the most up to date information available when the filing was prepared. At that time, the Company used the PIRA Energy Group's price forecast for Henry Hub Spot which was published in January 2006. This was the most recent information available when the Company put together its volume forecast budget in April 2006.

The Company's evidence forecast a continuing decline in average use.

The Company noted that its 2007 General Service sales volumes forecast reflects a decrease of 99 million cubic metres, as compared to the 2006 estimate, due to declining average use per customer.

Efficiency of gas appliances and relatively high and volatile gas prices were identified by the Company as key reasons for the decline in average use.

The Company's evidence indicated that gas prices accounted for 62% of the decrease in Residential gas consumption and for 19.9% of the decrease in apartment /commercial/ industrial gas consumption.

Positions of the Parties

While no intervenors disputed the integrity of the average use model the Company used to generate its average use forecast, VECC and Energy Probe questioned the timeliness and source of the gas price forecast which was reflected in the model utilized to forecast average use. Their submissions received the support of IGUA, Schools and CCC.

VECC expressed concern with the forecasted decline in normalized average use and volumes in the residential and apartment sectors, and highlighted the projected increase in natural gas prices as the dominant factor driving the forecasted decrease in general service volumes. In this regard VECC submitted that Enbridge made two material errors when forecasting the normalized average use for residential (Rate 1) customers by i) relying on the PIRA Energy Group forecast as opposed to the Board approved QRAM price forecasts, and ii) relying on forecasts from Q1, 2006 when materially different actual and forecasted natural gas prices for 2006 and 2007 are available.

Energy Probe submitted that the real energy price forecast, a key input into the regression models for both the Rate 1 and Rate 6 average use equations, should be updated to reflect the most recent information available on the basis that it has a material impact. Energy Probe expressed concerned with the timing of the information used to prepare the 2007 test year average use per customer forecast. Although accepting the view held by Enbridge's witnesses that it is not possible to update the entire rate filing, Energy Probe argued that it is appropriate to update for significant changes that have taken place since April of 2006.

The Company disagreed with the intervenors' assertion that the gas price forecasts should be updated to reflect more recent information. The Company noted that the nature of forward test year cost of service regulation is that all of the Company's budgets are set on a forecast basis and then submitted to the Board for approval. Selective updating, while less cumbersome and time-consuming than full blown update, could present a misleading or inconsistent picture and would encourage opportunistic behaviour by intervenors. In the Company's view, the fair approach in this case is to reject the intervenors call for selective updates and instead rely on the consistent information that was available at the time that the Company prepared its application.

Board Findings

The Board notes that no intervenor challenged the accuracy of the volumes put forward by the Company or the assumptions imbedded in the average use model. Nor does the Company question the accuracy of the volumes put forward by VECC and Energy Probe in the respective proposals. The differences in the proposals are in the source of the reference price and the timing of obtaining the reference.

The question before the Board is one of fundamental importance as it deals with the basic principles associated with the filing of an application and the interrelation and interdependencies of various application components.

In establishing fair and reasonable rates the Board considers many factors and weighs many pros and cons. One of these balancing exercises is the valuing of the use of the most recent and therefore most accurate data against the value of being able to complete application processes in a timely manner and with a degree of certainty by all involved that the original application will be heard as filed, except for pre-determined or exceptional circumstances.

In this particular case the intervenors representing consumer groups support the insertion of fresh information into the application which would result in higher projected usage and therefore a lower projected revenue requirement for the Company. One can easily imagine the Company putting forward the same type of proposition if during the proceeding it became clear that the starting assumption on gas forecast prices was a less favourable input than a current reference price indicated. In essence, the application in such a paradigm would remain a dynamic document until the record would be considered closed. Although such dynamism may be appropriate in certain circumstances, it is impractical in this context.

The Board accepts that the most recent data should be used in the preparation of an application in the establishing of rates. The Board does not consider the data updating propositions of Energy Probe and VECC to be practical. The Board accepts the Company's position that there are too many interrelated matters and assumptions that must be taken into account if it were to update the particular elements argued for in its rates application.

The Board accepts the Company's average use-per-customer forecasts.

CONTRACT GAS VOLUME AND REVENUE FORECAST

This section deals with Issue 2.5, namely, Is the proposed 2007 contract gas volume and revenue forecast appropriate?

Contract customers are customers with annual consumption of 340,000 m^3 or greater who enter into a service contract with the Company and are in the 100, 200 and 300 series of rates. The volume forecast was prepared in March 2006, and incorporated the most up to date information available at the time when the filing was prepared.

In its pre-filed evidence, the Company sought approval of its contract gas volume forecast 4,131.7 10^6m^3 for the 2007 test year. Subsequently, in its argument-in-chief, the Company increased the forecast to 4,134.3 10^6m^3 to reflect the Company's amended degree days forecast proposals.

The Company characterised the development of the volume forecast for the contract market as a grass roots approach; it is prepared by aggregating the information collected by its account executives in consultation with all contract customers. The aggregate contract gas volume budget that results is then adjusted to take account of the degree day forecast on the weather-sensitive portion of the customers' forecast volumes to form the total contract volumes forecast for the test year.

IGUA submitted that it had no quarrel with Company's 2007 contract gas volume forecast apart from the weather projection methodology used to derive a forecast of 3,805 degree days for the weather sensitive portion. No other intervenors made submissions.

The Board accepts the non-weather sensitive component of the 2007 contract gas volumes forecast as filed. The Board directs the Company to reflect the 2007 test year contract sales volume forecast consistent with the Board's findings in the Forecast of

Degree Days chapter of this Decision pertaining to the degree day methodology the Company is to use to forecast weather sensitive volumes.

GENERAL SERVICE VOLUME AND REVENUE FORECAST

This section deals with Issue 2.6, namely, Is the proposed 2007 General Service gas volume and revenue forecast appropriate?

The Company in its pre-filed evidence sought approval of its General Service volume forecast of 7,625.8 10^6m^3 for the 2007 test year. Subsequently, in its argument-in-chief, the Company increased it to 7642.0 10^6m^3 to reflects the Company's amended degree days forecast proposals.

The Company indicated that the forecast was derived using regression models (average use) for Rates 1 and 6 and a forecast for Rate 9 consistent with past practices.

Intervenor and Company submissions focused on the Degree Day forecast and average use forecast, both of which are major inputs into the General Service forecast.

General Service volume forecast relates to degree day methodology and the derivation of use per customer amounts for the 2007 test year. The Board's findings in this regard are found in the Forecast of Degree Days and Average Use-Per-Customer chapters of this Decision. No submissions were made regarding other aspects of the General Service forecast.

The Board directs the Company to update the 2007 test year General Service forecast commensurate with this Decision as it pertains to degree day methodology and use per customer amounts.

FUEL SWITCHING

The settlement proposal approved by all parties other than GEC and Pollution Probe reduced the Company's proposed "Other O & M Budget" for the 2007 test year from $200.8 million to $181.5 million. Parties other than GEC and Pollution Probe agreed that they would not take any position as to how the Company should allocate this $181.5 million. Out of the $181.5 million approximately $3 million relates to fuel switching.

At the oral hearing Enbridge indicated that it will have to consider how it will allocate the $181.5 million amongst its different departments as a result of the Settlement Agreement. Consequently, the Opportunity Development budget, which subsumes fuel switching, would be allocated an amount lower than the $30.8 million budgeted in the pre-filed evidence.

Positions of the Parties

All parties with the exception of GEC and Pollution Probe agreed that Enbridge should have the required flexibility to allocate the envelope amount of $181.5 million.

GEC and Pollution Probe argued that the Board should approve Enbridge's fuel switching budget as filed and earmark an additional $11.5 million for incremental fuel switching expenditures as part of a joint Enbridge/OPA fuel switching program. Pollution Probe cited several benefits of fuel switching including reducing greenhouse gas emissions by reducing the demand for electricity, lowering natural gas distribution rates and reducing the need for new high-cost natural gas-fired power plants. Accordingly, GEC and Pollution Probe argued:

1. The Board should approve Enbridge's fuel switching budget as initially filed minus the costs associated with those programs that fail the Total

Resource Cost (TRC) test. This includes outdoor barbeques, garage heaters, pool heaters and gas fireplaces.

2. The Board should approve an additional $11.5 million of fuel switching expenditures.

3. The Board should establish a variance account with respect to Enbridge's fuel switching budget that returns any of the unspent dollars to ratepayers, and

4. The Board should direct Enbridge to evaluate the actual TRC net benefits of its fuel switching programs at the end of fiscal 2007. Enbridge should also be subjected to the evaluation and auditing process similar to a Demand Side Management ("DSM") program.

VECC was a signatory to the Settlement Agreement on Other O&M but kept its options open to advance arguments that the Company allocate the budgeted amount of $925,000 for Low-Income fuel switching initiatives. VECC argued that according to the settlement reached in the generic DSM proceeding, Enbridge was committed to budget a minimum of $1.3 million, or 14% of its residential DSM program budget, whichever is greater, for low-income customer programs. Accordingly, Enbridge should commit to spend the budgeted amount of $925,000 on Low-Income fuel switching initiatives as stated in the pre-filed evidence. VECC submitted that in order to ensure success of Low-Income fuel switching programs, a minimum amount needs to be spent so as to reach a critical mass of customers. According to VECC this amount is much higher than 14 percent of the residential program budget that Enbridge committed to spending at the oral hearing. VECC argued that this proportion should be close to 30%.

The Company in its Argument-in-Chief maintained that it required flexibility to allocate its budgets within the Other O&M envelope. Enbridge argued that its managers must have the flexibility to respond to changing market conditions and ensure a reliable and safe natural gas system. Enbridge rejected suggestions of GEC and Pollution Probe of setting up a variance account to track the money spent on fuel switching activities citing that the Company should not be locked in terms of spending on a particular area.

The Company further maintained that the Board should not micro-manage Enbridge's budget on a program-by-program basis. It also rejected suggestions of spending additional expenditures on fuel switching activities. The Company indicated that the Other O&M envelope of $181.5 million is the level of spending that ratepayer groups are prepared to accept and the Company has to work within this envelope in determining its budget priorities. Spending additional amounts will lead to short term rate impacts that the ratepayer groups are not prepared to accept.

The Company also rejected the recommendation of some intervenors that Enbridge should not pursue load growth or fuel switching programs that generate a negative net TRC. According to the Company, the TRC analysis does not work with respect to many load growth programs and therefore does not assist in the determination of whether the program should be continued or not. One example that the Company cited in its Argument-in-Chief was the proposed residential fireplace program. Although the program has a favourable Net Present Value (NPV), it does not pass the TRC test. The Company has argued that if the TRC measure is used as the determining factor then the Company would have to discontinue all its activities with respect to natural gas fireplaces. The Company maintained that if it is prohibited from implementing all programs that generate a negative TRC, then it would have to discontinue the electronically commutated motor program ("ECM") which increases the efficiency of the motor on a furnace saving electric load, while incrementally adding additional gas consumption. The Company further added that this program has been strongly supported by intervenors in the past.

The Company also referenced the California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects that points to the weaknesses of the TRC test in evaluating load growth initiatives. The Company indicated that it puts greater emphasis on NPV as an appropriate measure for load growth and fuel switching initiatives as it provides a better basis to assess whether the program will not be a financial burden on ratepayers. Based on the above argument, the Company asked the Board to reject any suggestions that it be prohibited from undertaking programs that support the lawful use of natural gas appliances by its customers.

Board Findings

In the 2006 Rate Case (EB-2005-0001), the Board did not look at individual departmental budgets to determine its findings on Enbridge's Other O&M. Rather it looked at cost per customer. The Board noted on Page 97 of the Decision:

> The Board expects that productivity improvements, or budget prioritization, will allow Enbridge to manage cost pressure within this envelope.

The Board did not allocate specific amounts to different departments and relied on Enbridge to decide on how best to manage its operations within a specific envelope. In the current proceeding, Enbridge and other parties have agreed to an envelope amount of $181.5 million to meet the Company's Other O&M requirements. The Board does not see any reason for micro-managing Enbridge's budget. Enbridge has been allocated an envelope amount and requires sufficient flexibility to meet its operational priorities. The Board will therefore not make any determination on the amount that Enbridge should spend on fuel switching initiatives and will neither ask Enbridge to set up a variance account to track expenses on such initiatives.

In making this finding, the Board rejected GEC and Pollution Probe's recommendation that Enbridge should be asked to significantly ramp up its spending on fuel switching initiatives and spend an additional $11.5 million on such initiatives. Although such initiatives can provide additional benefits, there is no evidence to suggest that Enbridge can spend more money in a cost-effective way on fuel switching in the interests of ratepayers.

GEC and Pollution Probe's recommendation that Enbridge should not be allowed to promote fuel switching and load growth initiatives with appliances that fail the TRC test has merit. Promoting appliances with a negative TRC seems inconsistent with the Government of Ontario's goal of creating a culture of conservation and carries negative societal benefits in terms of increasing emission of greenhouse gases. Accordingly, the Board directs Enbridge to pursue only those initiatives that meet the TRC test.

Enbridge's claim that if it is prohibited from implementing all programs that generate a negative TRC, then it would have to discontinue the electronically commutated motor program ("ECM") is not correct. Although the TRC may be negative in the case of the ECM program, this initiative is not evaluated separately from the furnace. Consequently, the high-efficiency furnace that uses an ECM has a positive TRC. This is not the case for a natural gas fireplace, barbecue, outdoor heater or a pool heater.

The Board does not see any need to evaluate the actual TRC net benefits of Enbridge's fuel switching programs at the end of fiscal 2007. The Board has recently approved a three-year DSM framework for Enbridge and Union. One of the key reasons for implementing a three-year framework was to avoid detailed ongoing scrutiny of the utility's DSM programs. It would be inappropriate to move backward and subject Enbridge's fuel switching initiatives to the prior level of scrutiny afforded to DSM.

The final matter to be addressed in this section of the Decision concerns the VECC argument regarding the minimum amount that the Company should be spending on fuel switching for low income groups. VECC essentially argues that the reduction in the O & M budget agreed to in the Settlement Proposal should not be applied to this segment and suggests that the minimum amount should be closer to $925,000 which is close to 30% of the total amount. The Board does not accept this submission but does accept the submission that the amount of fuel switching expenditure on low income groups should be not less than 14% approved by the Board in the generic DSM Decision pertaining to DSM programs. In making this finding, the Board is not making a nexus between DSM and fuel switching other than the 14% level also being an appropriate allocation of expenditures geared to lower income groups.

ENERGYLINK PROGRAM

EnergyLink is a channel partnership with HVAC contractors intended to assist Enbridge customers find natural gas solutions using a referral system that can be accessed either through the Internet or the Company's call centre. Customers are given a choice of three service providers who meet their requirements.

The Company initiated a phased roll-out of EnergyLink. The first phase which included customer referrals for natural gas furnaces, boilers, fireplaces and water heaters, as well as referrals for installation of natural gas appliances was launched in December of 2006. In the second phase, the Company will create a retailer locator that will help customers find retailers of natural gas appliances.

Enbridge has budgeted an amount of $1.3 million in O&M spending on EnergyLink and a further $2.75 million in capital expenditures. A partial settlement was reached for the 2007 capital budget and the overall level of "Other O&M". However, capital and O&M spending on the EnergyLink program remained unsettled items other than the agreement that the Board's decision in this matter would not impact the overall test year capital or O&M budget.

With the exception of GEC and Pollution Probe, intervenors did not support the EnergyLink program. The main issues are as follows:

1. Whether the Board approved the program in its Decision in EB-2005-0001 or otherwise?

2. If the Board has not approved the EnergyLink program, should the Board now approve this program?

3. If the Board does not approve the EnergyLink program, should the costs incurred be recovered from the ratepayers?

Positions of the Parties

CCC disagreed with the Company that the Board has approved the EnergyLink program. According to CCC, Enbridge did not provide detailed evidence in the 2006 rate case of what the EnergyLink program consisted of so that the implications of approving the program could be fully examined. In Union Energy's view, Enbridge cannot pursue EnergyLink without prior Board approval and in the event that Enbridge seeks Board approval, it should not be permitted to allocate funds from either the 2007 Capital Budget or the Other O&M Budget to EnergyLink. VECC, based on its calculations of unit costs of $60 per call or $20 per contractor referral, argued that these unit costs appeared to be high and it was not clear that EnergyLink was a cost-effective service for ratepayers.

CCC, HVAC, and IGUA are concerned about the risk of an anti-competitive impact from this program. They argued that the customers would associate the EnergyLink program with Enbridge and think that it is the primary source of service for gas-fired equipment.

HVAC specifically argued that companies who promote their own brand name face a new hurdle, namely one of having to compete with the powerful Enbridge/EnergyLink brand. HVAC companies will have to make a decision whether to market under the EnergyLink brand or their own brand, with the latter option being significantly more expensive. In addition, Enbridge will restrict competitors' efforts to compete with the Enbridge/EnergyLink brand and will restrict advertising by third parties in Enbridge's envelope by preventing companies from mentioning EnergyLink.

Direct Energy argued that Enbridge should have continued to work with the contractor community and focused its efforts on marketing and promoting the benefits of natural gas, rather than developing a branded referral service that would compete against established marketing channels and existing referral services. Direct Energy stated that, like many other service providers, it felt compelled to join the EnergyLink program, given the potential for negative customer perception from not being accepted as a qualified contractor by Enbridge. However, having the benefit of full disclosure of the intent and scope of the program, Direct Energy submitted that it strongly opposes the continuation of EnergyLink and recommended that the Board disallow the further use of ratepayer dollars.

HVAC asked that the Board order the Company to terminate the EnergyLink program immediately and CCC submitted that the Board should not approve the EnergyLink program in view of its possible adverse impact on the competitive market.

Union Energy, HVAC and IGUA submitted that one of the major reasons for developing this program is to provide a platform for Enbridge Financial Services Inc.'s financing program and provide benefits to the unregulated affiliates of the utility. CCC argued that the returns to Enbridge's parent from the financing program of EnergyLink would be very substantial according to a presentation attached to an exhibit by the Company and that no part of the cost of the EnergyLink program should be recovered from ratepayers.

Union Energy and HVAC also questioned the projected success of the program. In reply to an Undertaking (J10.7), the Company indicated that it expects 1,200 customers to switch to a natural gas furnace from an electric or oil furnace as a result of the EnergyLink program. HVAC submitted that this forecast is unrealistic. The Company forecasts replacement of 36,191 furnaces from electric/oil to natural gas. Considering that 90% of Enbridge's households in their franchise area have a natural gas furnace, this would imply a replacement rate of over 20%. Since the life of an electric or oil furnace is 15 to 20 years, this indicates that switching is three to four times the normal replacement rate. HVAC and Union Energy submitted that Enbridge had not provided credible evidence as to how EnergyLink is going to cause these new sales.

HVAC also questioned the Company's forecast with respect to water heaters. The Company has two types of water heater programs, those in which an electric water heater is switched to gas and those under which a new water heater is installed, usually in new construction. The Company's direct programs forecast 1,518 participants and this program show a negative NPV (Exhibit J9.2). The reason for the negative NPV is the amount paid to participants as incentives. However, when the same program is being promoted through EnergyLink, the Company is projecting 2,500 participants (Exhibit J10.7). Since this program has a positive NPV, it indicates no incentives. HVAC argued that it is difficult to believe that a program that gives an incentive cheque to a customer will be significantly less successful than the EnergyLink program.

On the other hand, GEC and Pollution Probe submitted that they support the EnergyLink proposal as a means to facilitate DSM and fuel switching, and according to GEC, so long as the mechanism is not used to encourage inefficient end uses. Pollution Probe submitted that the Board’s approval of the EnergyLink program budget should be conditional on Enbridge issuing a RFP to obtain competitive bids from financial institutions for low interest financing. GEC commented that the parties who are opposed to the EnergyLink program on the basis that it was a platform to channel financing opportunities to Energy Financial Solutions Inc. were signatories to a settlement allowing the on-bill financing proposal to proceed, presumably believing that any possible abuse of affiliate relationship and any corrosion of the competitive market due to bill-financing is protected against in that agreement. Accordingly, GEC submitted that it was puzzled by the suggestion of some parties that the EnergyLink program is a tool to destroy competition.

VECC stated that of the purposes for the EnergyLink identified by Enbridge, the provision of an easy connection for customers with service providers was the only goal which VECC accepted and that it does not disagree that an enhanced referral system located in the utility could be of benefit to customers, to the extent that it provides the 25,000 unsolicited calls from customers with referrals to qualified service/installation contractors.

IGUA and Union Energy argued that activities such as the rental of gas-fired equipment, the provision of a contract referral service, are not within the scope of business activities in which Enbridge can engage as a Board regulated natural gas transmission, distribution and storage utility, quoting the undertakings Enbridge gave the Lieutenant Governor in Council which were approved by Order in Council on December 9, 1998:

"….shall not, except through an affiliate, carry on any business activity other than the transmission, distribution or storage of gas, without the prior approval of the Board." Furthermore, IGUA, with respect to business activities pertaining to the rental of gas-fired equipment, quoted paragraph 3.2.5 from the Board's March 31, 1999 Decision with Reasons in E.B.O. 179-14/15: "The Board's finding with respect to retention of the rental program in the core utility is supported by its view of current regulatory policy, which encourages the development of a "pure utility", stripped of non-monopoly services……..Retaining the Company's rental program in the core utility does not allow appropriate costing principles to prevail." And according to paragraph 3.2.6 "The Board would accept the program, for the time being, on a non-utility basis within the Company, with elimination of the program's costs on a fully allocated basis." Union Energy submitted that the subsidy burden that EnergyLink imposes on ratepayers should be evaluated on a fully allocated cost basis and eliminated in its entirety from Enbridge's revenue requirement. IGUA argued that since the EnergyLink program is incompatible with the "pure utility" policy reflected in the Company's current undertakings, the utility is prohibited from carrying on any of the EnergyLink program activities without prior Board approval. VECC submitted that the Board should not approve the cost consequences of EnergyLink for 2007 since it is not a core distribution utility service.

The Company argued that it has already received approval for EnergyLink in the 2006 rate case. The Company did indicate then that it planned to introduce a channel strategy to facilitate natural gas solutions for customers. The Company did not however specifically mention the EnergyLink program. Before EnergyLink was launched by the Company, Mr. Hewson the Board's Chief Compliance Officer received a letter from the HVAC Coalition expressing concern about the program. Mr. Hewson indicated that it did not appear that EnergyLink was outside the requirement of the Gas Distribution Access Rule ("GDAR") or any other regulatory parameters within which Enbridge is permitted to distribute natural gas in Ontario.

With respect to the arguments by certain intervenors that based on the undertakings that the Company has given to the Lieutenant Governor in Council Enbridge cannot engage in a business activity other than the transmission, distribution or storage of gas unless it has prior Board approval, the Company indicated that there are a wide range of activities that the Company undertakes on a daily basis that support the core activities of the Company such as maintaining a fleet of vehicles or conducting financial studies. The Company submitted that EnergyLink falls precisely into the same category.

The Company reiterated that it is confronting a situation of market stagnation. Average use per customer has been declining and this is expected to continue due to the impact of conservation, updated codes and standards and higher and more volatile natural gas prices. This market stagnation has resulted in negative pressure on Enbridge's market share and throughput. To support its argument, the Company cited the decreasing penetration of gas water heaters in the customer replacement market and the increasing market share of electric fireplaces. EnergyLink would address these issues by increasing throughput and penetration of natural gas-fired appliances.

Another factor according to the Company that underlies the EnergyLink program is customer confusion about who to call for information regarding natural gas equipment and appliances. The Company indicated that customers see Enbridge as an unbiased party and a reliable provider of information[6]. Thus, it is no surprise that customers contact the gas utility for information on natural gas appliances. The Company has estimated that it receives 25,000 calls per year of this nature. EnergyLink would satisfy these customers by providing referrals to qualified contractors. More importantly, customers do not pay any fees for referrals and there is no charge to contractors to participate in the program.

The Company stressed the benefits of EnergyLink that it provides to ratepayers by increasing throughput. The program has a net present value of $4.1 million. The program provides a valuable service to customers and might assist customers in selecting a natural gas solution over an electric one. The Company also cited benefits to members in the form of free leads, free access to the EnergyLink brand, exclusive

[6] According to a survey done by Enbridge and filed in evidence, 75% of the Company's customers would trust Enbridge to provide reliable and credible information about contractors/retailers: Exhibit I-26-17, Attachment 3, page 8 of 19

sales campaigns, co-op advertising, access to training opportunities and other sales tools.

One issue specifically scrutinized by the intervenors was a proposal to offer a financing program whereby customers could finance their equipment purchase through the Enbridge bill. The Company indicated that Enbridge Solutions has still not made a decision about whether it intends offering a financing program and that EnergyLink is not a platform to launch an affiliate's financing program.

The Company argued that the issues raised by other parties have not demonstrated that the program is fundamentally flawed but rather the issues have merely created suspicions around EnergyLink. In that regard, in its reply argument, Enbridge made six commitments to the Board to address certain issues around this program:

1. Enbridge will send out an immediate communication to all EnergyLink contractors making it clear that they do not have to belong to EnergyLink to access the bill.

2. Enbridge will seek opportunities to encourage low interest financing for energy efficiency products or measures to be part of its market development activities and it will seek to include as many interested financing entities as possible.

3. Enbridge will investigate working with the TSSA in connection with independently qualifying these EnergyLink contractors.

4. Enbridge will establish an EnergyLink advisory group. This group will not be funded by ratepayers, but will be comprised of individual EnergyLink contractors to provide guidance and feedback and suggest continuous improvements to the program.

5. Enbridge will report to the Board in an appropriate time and fashion the following information: prior to launch, its plans regarding Phase II of EnergyLink with respect to retail options for natural gas white goods and

after completion of 2007, performance reporting including number of customers, number of referrals, customer satisfaction results, level of influence of EnergyLink, added load and DSM, and results of a contractor survey.

6. In full compliance with the Affiliate Relationship Code, Enbridge will continue to ensure that no non-public information about EnergyLink is communicated to any unregulated affiliate.

In response some intervenors submitted that the so-called “commitments” were materially new and untested. They were not introduced as evidence and should not be considered in this proceeding as they are inadmissible. The HVAC Coalition submitted that the commitments failed to address the fundamental problems with the EnergyLink program and its harmful impacts on the competitive marketplace and the Company’s ratepayers.

Board Findings

Enbridge is a leader in conservation initiatives in the Province and a considerable amount of consumer dollars are invested in this activity. The EnergyLink Program is designed to do exactly the opposite, namely to use consumer dollars to fund programs to increase the use of gas. In some cases, these projects would not meet the TRC standards that are used to evaluate their conservation initiatives. The result is that consumers would be receiving confusing messages and funding competing programs.

The other concern is the potential anti-competitive aspect of the EnergyLink Program. Much of this hearing centered on this issue. While the six commitments made by Enbridge in its reply argument attempt to address the anti-competitive concerns, these concerns continue to exist. There is no question that leads and inquiries go to the gas company and without a referral program many of these leads may be wasted. On the other hand, the evidence before the Board is that there is a growing and substantial industry capable of meeting market requirements. The unintended result of the Enbridge program might be to dampen this competitive development.

The Board finds that there is no clear evidence of market failure that requires the intervention of Enbridge through this Program. The Board is not convinced that the cost of the Program justify the benefits. The concern with declining average use remains of course. It should be addressed, in the Board's view in a more fundamental fashion as has been done in a number of jurisdictions that dealt with the issue of declining use.

Enbridge argues that the Board has accepted and approved the EnergLink Program in its previous rate case. The intervenors disagree. The evidence provided by the Company in that proceeding was limited. It is difficult to conceive that the Board intended to approve or approved a Program of the nature described in this hearing with its attendant costs based on the evidence, or lack of, that was before it. The Board will allow the Company however to recover the costs incurred to date but finds that no further costs should be recoverable from the ratepayers.

The Company indicated that it had budgeted $1.3 million in Operating and Maintenance expenses and $2.7 million in Capital expenditures for 2007 and that it estimates to have spent $3.3 million in capital in 2006. The Board finds that for ratemaking purposes the Company's 2007 Other Operating and Maintenance Budget shall be reduced by $1.3 million to $180.2 million. The 2007 rate base shall be updated to reflect the removal of any EnergyLink related capital expenditures. The Board understands that the Company in good faith has incurred actual costs in operating and maintenance expenses and capital expenditures related to the EnergyLink program and it would be unfair to the company to have to absorb these costs. The Board approves the recovery of the 2007 Operating and Maintenance expenses incurred as of the date of this decision, but no more than $1.3 million. The Board approves the recovery of capital expenditures, but no more than the 2006 estimated and 2007 budgeted amounts spent to the date of this decision. The balances will be amortized evenly over three years starting in 2007. The Company therefore shall include a rate rider as part of its draft 2007 rate order, with appropriate supporting documentation as to the calculation of the specific amounts.

OPEN BILL ACCESS

This section addresses the “non-settled” aspect of Issue 7.5. Issue 7.5, “Is the Applicant’s proposal of open bill access appropriate and consistent with the direction in EB-2005-0001” has two aspects, (i) third party billing information included on the Enbridge bill (“billing services”) and (ii) the inclusion of third party inserts in the Enbridge envelope (“inserts”). “Billing services” was completely resolved in the 2007 Settlement Proposal. “Inserts” was not.

Certain parties (Enbridge, Direct Energy, OESLP and Union Energy) agreed to settle the billing insert component on the basis that the Company can proceed with the Insert Service subject terms listed in Appendix D page 1 of the Settlement Proposal. HVAC, VECC and Schools did not agree with the proposed settlement and CCC opposed the settlement in order that it may be permitted to pursue cross examination on the issue. GEC and Pollution Probe reserved the right to pursue in the hearing whether the Board should order that third parties not be allowed to use the billing services for the billing of specific products on the basis of their environmental attributes. Superior opposed the proposed settlement on the principle that it is not supportive of a settlement position that would allow for the Company to promote system gas through billing inserts.

Open Bill Access was an issue in the 2006 test year proceeding (EB-2005-0001/EB-2005-0437). In that Decision, the Board indicated that although that there may be merit in sharing the bill with service providers, Enbridge had to make a more thorough case. The Board noted that concerns, including ratepayer benefits, impact on the public interest, the potential for customer confusion, non-discriminatory access, and interim versus comprehensive solutions needed to be addressed.

Positions of the Parties

The Company's basic justification for the program is to increase the use of natural gas to offset a declining rate of usage on a per customer basis through the promotion of sales of goods which utilize natural gas. According to the Company, the program will also fulfill the expectations of customers that Enbridge will provide them with information about natural gas products and services while providing them with the option of opting out from receiving such information. In addition, the Company asserts that the program will provide an additional ratepayer benefit through earnings sharing and lower cost of service, provide additional opportunities for DSM and enhance customer convenience and improve customer satisfaction.

Parties supporting the program submitted that the program would provide equal and fair access to both big and small vendors to the envelope and would be in the public interest given ratepayer financial benefits and customer communications.

GEC and Pollution Probe supported the program on condition that it not be used to promote inefficient products and services. The results should be TRC positive and consistent with DSM purposes.

Parties disagreeing with the program noted that the presence of third party inserts will obscure and dilute the impact of safety and regulatory inserts, will cause customer confusion, that survey data supporting customer interest in receiving the inserts is ambiguous and that the 50/50 income sharing arrangements are inadequate.

HVAC, as a potential user of the service, submitted that the Board direct the Company not to proceed with a bill insert service at this time because risks and inconveniences to ratepayers exceed any benefits, the program does not comply with the Board's direction in providing open access, the bidding process does not meet the test of being non-discriminatory, and the Company still has to demonstrate a bidding structure that accomplishes the goals of open access and revenue maximization. HVAC also raised the question of whether, in the first instance, it is appropriate for a utility to use its envelope to sell the services of private companies.

Board Findings

There are a number of criticisms of the procedures the Company developed for bill insert service.

There is no question that granting access to the bill for bill insert service can improve the competitive framework. That explains the reason the Program is supported by intervenors such as Direct Energy. There are complaints however by HVAC that the bidding structure for mid-size companies is not satisfactory. The Board believes that these concerns should be carefully investigated by Enbridge with a view to meeting the concerns of HVAC consortium in a revised bidding structure. Nonetheless, the Board believes that the Program is in the public interest subject to certain conditions expressed below.

First, there is a concern that crowding the bill with inserts tends to weaken the message for all participants and as a result a portion of the readers actually do not pay any attention to the inserts at all. The Board believes that the suggestion made by CCC has some merit and where a safety notice or rate increase is being publicized through a bill insert, no other material should be included in the bill for that particular mailing.

The Board also has some sympathy with the submissions made by GEC and Pollution Probe and agrees that access to Enbridge's billing envelope should be consistent with the Company's DSM Program and restricted to appliances so that they meet existing TRC tests. However, the Board concludes this would burden the initiative with an undue administrative oversight requirement and instead relies on the Company's exercise of discretion on this matter.

The last matter at issue is the income-sharing aspect. Enbridge proposes a 50/50 split in income received from the bill insert service. The infrastructure costs of this service are paid for by the ratepayers while the incremental costs are paid for by the companies seeking access to the bill. The Company forecasts the maximum ratepayer benefit in the order of $2.5 million. The question is how are the profits to be shared. This is admittedly a matter of judgment but in the circumstances the Board accepts the Company's proposed 50/50 split.

Accordingly, the Board accepts the proposed program, subject to the aforementioned provisions, as described in Appendix D of the 2007 Settlement Proposal.

RISK MANAGEMENT PROGRAM

In the Company's last year's proceeding (EB 2005-0001), the Board stated in its decision as follows:

> The question that remains is the extent to which Enbridge's risk management program is redundant or represents a useful and cost effective tool to reduce consumer price volatility in a fair and reasonable way.
>
> …
>
> No evidence has been provided that demonstrates whether the hedging activity had a material effect on the volatility experienced by customers, given the effects of QRAM, the PGVA, and equal billing programs over the same period.

and directed:

…. Enbridge to prepare for consideration in its next rates case evidence which demonstrates the extent to which the Company's hedging activities in 2003, 2004, and 2005 would have resulted in reductions in volatility for its customers, had it applied the proposed $75 action level.

Issue 3.10 in this proceeding asks: "Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?" Issue 3.13 deals with the disposition of existing deferral and variance accounts, including the Gas Supply Risk Management Program Deferral Account.

In response to these issues, the Company is seeking approval for two things:

(a) the continuation of its Risk Management Program; and

(b) closing to rate base of the expenditures incurred upgrading from an Excel spreadsheet to a database format which have been recorded in the Gas Supply Risk Management Program Deferral Account.

While the risk management program affects all customers that are on system gas who may be served under Rates 1, 6 or 10, the Company acknowledged that the objectives of the program are aimed at residential and small volume general service customers. The Company also acknowledged that it is the customers that are not on direct purchase and the customers that are not on budget billing that are most affected by the program.

The Company has an optional budget billing plan where the customer, whether direct purchase or system gas, can smooth rate fluctuations by making payments of equal amounts. The Company also has a Board-approved QRAM mechanism where commodity prices are updated quarterly to reflect more recent forecasts. The updated forecasts also form the new base for the PGVA, a mechanism for capturing the differences between forecast and actual commodity costs to the Company. Under the budget billing plan, the customer's forecast payments for a twelve month period starting in September are equalised with July being the true-up month. For August, actual use is being billed. A customer's bill is reviewed every three months and revisions to the amounts may be required to reflect the customer's natural gas usage or if there is a significant change in the reference price or both.

The Company acknowledged that if it terminated its risk management program, it would not affect its gas supply as the program is done through financial instruments only. The Company also indicated that even if it had a more frequent rate adjustment mechanism than quarterly, this may not have any impact on the price volatility that is happening in the physical market. The Company explained that any frequency of rate adjustment will have the potential to change the magnitude of the PGVA but the PGVA is driven mainly by the volatility in the forward 12-months prices.

The Company's evidence showed the impact of its Risk Management activities on the PGVA reference price from January 1, 2002 through to October 1, 2006. The

Company's evidence displays the actual PGVA reference price and what that price would have been without Risk Management activity built into it and the quarter-over-quarter change of the PGVA reference price for both the risk-managed and non risk-managed pricing scenarios. The variance of the risk-managed versus non risk-managed scenarios is calculated in absolute dollar terms per 10^3m^3. The evidence shows that, in general, risk management results in less volatility in the PGVA reference price. The quarter-over-quarter swings are muted by risk management. The largest variance is negative \$6.07 per 10^3 m^3. Generally, the volatility reduction over the period was in the \$1 to \$2 per 10^3 m^3 range.

The Company acknowledged that it did not provide the information or calculations sought by the Board in the previous decision to demonstrate whether the hedging activity had a material effect on the volatility experienced by consumers given the effect of QRAM, the PGVA and the budget billing plan. The Company explained that it would be very difficult to recreate that history given how the hedging program works with the trigger points and hedging instruments. It would be largely a theoretical exercise and the results would not be reliable.

In responding to questions whether the risk management program should be addressed as part of a pending review of the QRAM process, the Company indicated that this review is aimed at reviewing cost allocation issues to system gas and standardization of QRAM for Enbridge and Union Gas, and that the risk management issue can be assessed independently of this review.

The Company has recorded the sum of $691,500 in the 2006 Gas Supply Risk Management Program Deferral Account ("GSRMPDA"). These amounts were incurred by the Company converting from Excel spreadsheets to a database format, as recommended by RiskAdvisory in the RP-2003-0203 proceeding. In the last main rates case, the Board chose not to close the IT capital costs in rate base as requested by the Company and, instead, found that the balance should be disposed of according to the Board's decision in this case. The Company proposed that, even if the Board directed discontinuance of the risk management program, the capital costs should be recovered from ratepayers as these costs were prudently incurred. The Company noted that RiskAdvisory's recommendations to convert the format were at no time challenged by any party and that at the time the Company began incurring these costs, it had recently been told by the Board that risk management was of value to ratepayers and would be continued.

Tom Adams, on behalf of Energy Probe, calculated the impact of the program on customer bills to be no more than one percent. His evidence also noted the $107 million losses incurred by the program in the last five years and expressed concern of the intergenerational inequities that arise from those losses. He concluded that the Company's risk management program is redundant and is therefore neither a useful nor an effective tool for reducing volatility for the residential consumer.

The Company noted that Mr. Adams' evidence only shows the impact of the risk management program on the commodity price at points in time; not the difference in the volatility the customer experiences over the quarter-over-quarter change, which in the Company's view was the Board's direction in the previous rate case. When prices are compared at the same point in time, the Company argued, it is not going to give an indication of the volatility or the extent of the price change that a customer experiences. On the other hand, the Company's evidence shows exactly that.

Positions of the Parties

The Company noted that risk management is an activity common to utilities across North America and that the Board itself noted in its Decision with Reasons in the RP-2003-0203 proceeding that only one major Canadian gas utility does not have a risk management plan. The Company's risk management activities have been the subject of two customer surveys, regular reviews by the Board and a detailed examination by a recognized expert in risk management activities, RiskAdvisory, only several years ago. The purpose of such activities and the benefits to ratepayers have not changed, and while the Company has been undertaking risk management activities for many years, the evidence in support of it is very current, beginning with the 2003 Rates Case (RP-

2002-0133). In its Decision with Reasons, the Board found that risk management activities are of value to ratepayers.

Ratepayers should not conclude they have either benefited or lost because of the risk management activities in any specific year, because when one views the net impact of such activities over time, the net impact will change from positive to negative, or vice versa, from year to year. While there will be gains and losses in each year in which risk management activities are undertaken, the net effect over time will be close to zero.

As demonstrated by the Ipsos-Reid Survey filed in the proceeding, a significant majority of ratepayers favour the Company undertaking steps to mute price volatility. The fact that the Company is regulated does not and should not reduce the need to exhibit good business practices by responding favourably to reasonable service requests by customers.

When one examines the results of risk management activities over time by looking at the percentage reduction in quarterly price changes on a quarter over quarter basis, the results are material and of value to ratepayers. The estimated $170,000 annual O&M cost associated with risk management amounts to little cost on a per customer basis. For the same reasons that industrial customers undertake similar activities to moderate commodity price volatility, so too should residential and commercial customers on system gas similarly benefit from risk management activities undertaken on their behalf collectively.

The Company cautioned that the value of risk management activities to ratepayers not be confused with the impact on the monthly amounts payable by customers that subscribe to the budget billing plan, which is simply a budgeting tool for ratepayers - it does not have any impact on the commodity price otherwise payable. Customers on the budget plan can be subject to large increases and decreases in the monthly amount payable to reflect price and consumption changes. The direct purchase customers have already eliminated commodity price volatility by agreeing to a fixed commodity price. The reason why such customers opt for the plan is not to address commodity price volatility, but for budgeting and/or the smoothing of invoice amounts over the better part of a year.

Enbridge argued that Energy Probe fails to look at volatility from one quarter to the next, and instead expresses the results of risk management as simply a percentage of the commodity price at a particular point in time.

CCC supported the continuation of Enbridge's risk management program and proposed that a broad review of system gas pricing is the most appropriate forum to consider how best to weigh the objectives of providing meaningful pricing signals but at the same time minimizing volatility.

VECC also supported the continuation of the program and the clearing of the $691,000 deferral account as proposed by the Company and stated that any concerns about the program should be addresses in the Cost Allocation of System Gas and QRAM process generic review.

Energy Probe argued that the Company has not been able to demonstrate that its risk management program had a material effect on the price volatility experienced by customers. While the operating costs of the program are not substantial, large losses have been incurred and there is no indication that these large losses will not become even larger, giving heightened concerns for inter-generational inequities and non-price transparency. Energy Probe submitted that the program should be terminated, in an orderly fashion but noted that it is not opposed to the $691,000 expended amount to be closed to rate base.

IGUA submitted that the Board should focus on the program's incremental value to that of the combined effects of QRAM, the PGVA, and the budget billing program. In IGUA's view, neither the Enbridge nor Energy Probe's evidence completely addresses the issue of incremental value. IGUA argued that the Company's risk management program does nothing to reduce the volatility that remains inherent in the QRAM regime. IGUA noted that Enbridge's cumulative losses because of the risk management program should prompt the Board to seriously consider directing Enbridge to cease the program.

Should the Board be reluctant to treat Enbridge differently than Union Gas, then the programs for both utilities should be reviewed on the basis of their incremental value over and above the smoothing already produced by the QRAM, the PGVA and budget billing programs in the generic QRAM proceeding contemplated in the Board's 2007-08 business plan. As for the $691,000 expended amount, IGUA argued that it should not be recovered from ratepayers since Enbridge has failed to satisfy the Board's condition that the program has value.

Schools argued that it would be in the public interest to phase out the Company's risk management program as soon as reasonably possible as it has not delivered benefits over the costs. The program has had only a limited impact on reducing volatility and there are other less costly methods of reducing volatility, such as the budget billing plan. To the extent that the program does have any impact on reducing price volatility, it mutes price signals and thus it runs counter to promoting conservation and encouraging market choices.

Board Findings

The Company and others have placed much emphasis on what they perceive is being revealed by customer surveys on the Company's risk management activities. Results of customer surveys cannot and should not be determinative of disposing of a matter. The Board's mandate is to set just and reasonable rates, which involves a balancing of many considerations. A prime consideration is cost effectiveness. It is clear that the previous Board panel decided the way that it did with the benefit of the Ipsos-Reid survey. The Board panel in that case made the decision that it did, which was to enunciate certain tests under which the Company's program should be scrutinized.

The previous Board panel concluded that no evidence had been provided that demonstrated whether the hedging activity had a material effect on the volatility experienced by customers, given the effects of QRAM, the PGVA, and equal billing programs.

The Company explained that it was not feasible to do so in this case, given the way its hedging program operates, the change in threshold levels, the complexities in attempting to reconstruct history and the questionable reliability of the ultimate results. The Board accepts this.

This leaves the other finding of the previous Board panel. Namely, the extent to which Enbridge's risk management program is redundant or represents a useful and cost effective tool to reduce consumer price volatility in a fair and reasonable way.

The Board notes the Company's concerns that the value of risk management not be confused with the impact of the budget billing plan on the monthly amounts payable by customers that subscribe to the plan. But the conclusion cannot be any other than there is little if any value for customers on the budget plan. There is no offset to bill volatility for these customers. These customers make equal payments for ten months of the year, and they eventually pay the actual costs. Adjustments prior to true-up may be required from time to time but these can also be because of factors other than commodity price changes. The existence of a risk management program is not really that relevant or of value for those customers.

This leaves the system customers who are not on budget billing. The volatility reduction over the last five years was in the \$1 to \$2 per 10^3m^3 range, which is fairly small relative to the prevailing PGVA reference price. The impact on the total customer bill impact in percentage terms is very marginal. The Company's argument that the annual costs associated with the program are small is not persuasive. This can be said about many other program and activities costs. The relative small size of costs involved in a program should be only one consideration. Other considerations are also important.

The Board notes from the evidence that for the period January 2002 to October 2006, the impact of the program was an accumulated net loss of \$107.3 million. In 2006, the loss was \$110.5 million. For 2007, at the time of the hearing the position of the account was a loss of about \$16 million. Clearly, in the most recent five years at least, the program was not an effective enterprise. It came at a high cost to the consumer. It is possible that the losses may be reversed in the future. It is however questionable whether this is necessarily a zero-sum game. To have a zero-sum result from the current position as a starting point, gas prices going forward have to be assumed as trending upward, not just gyrating around their current level, and that there is no cost in engaging in hedging.

Further, losses or gains as a result of the program do have intergenerational impacts. These impacts can be significant at times. The $110 million loss in 2006 for example is a cost that will need to be recovered by customers who may not have been customers during the time the loss had occurred. Although inter-generational impacts cannot be avoided in every circumstance, they should be mitigated or avoided when it is possible and reasonable to do so.

The Company's and Energy Probe's evidence have satisfied the Board that the rate smoothing attributable to the Company's risk management program for the remaining system customers not on equal billing is marginal at best. While the annual costs of operating the program are of lesser concern to the Board, the inter-generational impacts in light of the substantial losses are of significant concern.

Given the program's minimal impact on the other system customers not currently on equal billing, the impact will likely be unnoticed by these customers. For these customers, the option is still available to take advantage of the Company's equal billing plan if they so choose.

For all of the above reasons, the Board directs the Company to cease its risk management program as soon as practical.

In reaching this conclusion, the Board has considered the arguments that Union has an approved risk management program. This panel of the Board is mindful that, to the extent possible and practical, Board regulatory policy should be consistent. However, it would not be appropriate on the basis of the evidence adduced in this proceeding for the Board to allow continuation of Enbridge's risk management program. It would similarly not be appropriate to defer this matter to the future Cost Allocation of System Gas and QRAM process generic review without ruling on the matter on the evidence adduced in this proceeding. In that this decision may have implications for Union in a future rates case, it would be up to parties to raise the issue in a future Union proceeding.

With respect to the $691,500 recorded in the 2006 Gas Supply Risk Management Program Deferral Account (“GSRMPDA”), the Board is mindful of the Company’s concern of the longer term problems for decision making, on IT projects specifically, if the test is something other than the prudence of undertaking these projects based on the information available to the Company at that time. Given the history of endorsement of the Company’s risk management program by intervenors and the Board, the Company’s decision to proceed with the implementation of the recommendation by its consultant is certainly understandable. In these circumstances, the Board will allow recovery of the costs recorded in the 2006 GSRMPDA. The 2007 draft rate order is to include the full disposition of this account in 2007 and Enbridge is to ensure there are no Risk Management related costs included in 2007 rate base. The Board considers appropriate that this amount will be recovered from system gas customers.

DEFERRAL AND VARIANCE ACCOUNTS

Issue 3.12 deals with the establishment of 2007 deferral and variance accounts. All except one of requested deferral and variance accounts were the subject of the Settlement Proposal accepted by the Board. With respect to Company's proposals regarding Customer Care and Open Bill Access related deferral accounts, the parties indicated that these would be addressed under Issues 7.2-7.4 and 7.5 respectively. In this regard, the establishment of a 2007 Open Bill Access Services Deferral Account remained unsettled as part of the larger Open Bill Access-Inserts issue and is addressed in the Open Bill Access Chapter of this Decision.

In the EB-2006-0021 Natural Gas Demand Side Management Generic Decision with Reasons, issued August 25, 2006, the Board ordered the creation of a deferral account to record any carbon dioxide offset credits that the Company might earn. The Company included this deferral account (the 2007 Carbon Dioxide Offset Credit Deferral Account) in this proceeding, which was not an issue but was filed for completeness.

Disposition of Existing Accounts

Issue 3.13 relates to the disposition of existing deferral and variance accounts. In the Settlement Proposal, there was an agreement to settle a number of existing deferral and variance accounts and to defer consideration of the clearance of others to a future date. The Company proposes to clear the balance of all settled accounts, adjusted to reflect the Board's decision in respect of accounts reviewed and tested during the hearing, together with the outstanding balance in the 2006 PGVA.

There was no agreement reached with respect to the disposition of six deferral accounts. One of these accounts, the 2006 Gas Supply Risk Management Program Deferral Account, was dealt with earlier in this Decision under Issue 3.10 "Risk Management Program". The following five deferral accounts will be discussed below:

2006 Electric Program Earnings Sharing Deferral Account (2006 EPESDA)

2006 Unbundled Rate Implementation Cost Deferral Account (2006 URICDA)

2006 Alliance Vector Appeal Cost Deferral Account (2006 AVACDA)

2005 and 2006 Gas Distribution Access Rule Costs Deferral Accounts (GDARCDA)

2006 Electric Program Earnings Sharing Deferral Account (EPESDA)

The Company proposes the disposition of $175,100 which amount has been recorded in this account as a credit to ratepayers. This represents 50% of the net revenue of the Electric Program earnings after deducting program costs. This account and the 50/50 sharing were approved by the Board in the EB-2005-0001 proceeding in its Partial Decision with Reasons, dated December 22, 2005.

CCC expressed concern with the "lack of evidence" provided in this case to support the calculation of the $1.45 million in gross revenue and the costs in material, service costs, and internal costs. CCC stated that while it accepts the clearance of this account as proposed, in the future the Company should provide detailed evidence in support of the calculation of net revenue and should be required to determine net revenue on a fully allocated cost basis. IGUA stated that it supports CCC's position with respect to this matter.

The Board notes that no party opposed the clearance of the balance on this account as proposed by the Company. The Board also notes that the DSM Generic Decision (EB-2006-0021) directed that, from 2007 onward, the gas utilities shall allocate their internal costs on a fully costed basis. The balance the Company seeks to dispose of relates to 2006. In any event, the Board accepts the Company's submission that, as this activity is new for the Company, the internal costs for 2007 will be minimal. The Board approves the clearance of the balance recorded in this account as proposed by the Company.

2006 Unbundled Rate Implementation Cost Deferral Account (URICDA)

The Company developed unbundled rates and services for power generation and large volume customers as part of the NGEIR proceeding, which concluded in August 2006. In that proceeding, all parties agreed that the Company should be kept whole with respect to the implementation and introduction of unbundled rates and services. Parties to the NGEIR Settlement Proposal agreed to support the establishment of the 2006 URICDA and to support the recovery by the Company of prudently incurred costs recorded in the account.

The amount recorded in this account which the Company proposes to be cleared to rates is $480,500. This is the cost to implement the new unbundled rates and services, including design, development and implementation of a manual tracking tool, training, communication, and customer education costs, as well as legal and staffing costs.

As part of the NGEIR proceeding, the Board was asked to consider a threshold issue about which customers should be responsible for the unbundled rates implementation of costs. In an oral decision delivered July 14, 2006, the Board found that these costs should be recovered from large volume customers. Accordingly, the Company proposed to recover these costs from all large volume customers, bundled or unbundled, based on customer numbers.

IGUA stated that it supports the Company's proposal to allocate the amount to the large volume rate classes using customer numbers as the allocator. However, IGUA noted that it reserves its rights with respect to the manner in which any credit balance accumulated in this account is cleared to rate classes in the future and reserves its right to seek a re-balancing of Rate 115 and the baseline from which this account will operate, in the event that Transalta continues to take service on Rate 115.

The Board notes that no party objected to the clearance of the balance in this account as proposed by the Company. The Board also finds the Company's proposal reasonable and approves it.

2006 Alliance Vector Appeal Cost Deferral Account (AVACDA)

In RP 2002-0032, the Board ruled that Enbridge could not recover some $11 million in costs arising from a contract to transport gas on the Alliance/Vector pipeline system. Enbridge appealed that ruling to the Divisional Court, which found that the Board had erred. The Board sought and was granted leave to appeal the decision by the Divisional Court to the Ontario Court of Appeal, which found that the Divisional Court had erred. Enbridge sought but was denied leave to appeal to the Supreme Court of Canada.

The Company has recorded costs of $529,000 plus interest in this Board-approved account. All of the costs, according to the Company, are external legal fees and disbursements associated with the Company's actions on the Board's application for leave to appeal to the Court of Appeal and the Company's application for leave to appeal to the Supreme Court, and none of the claimed costs are related to its own appeal to the Divisional Court.

During the 2006 rate case, the Company had planned to record relevant costs and seek approval for clearing these costs to rates by means of the Ontario Hearing Costs Variance Account. The Board, however, in its 2006 Decision, directed the Company to apply for a new deferral account specifically to capture the costs associated with the Alliance Vector appeal. The Company subsequently requested and received approval, under docket EB-2006-0144, to establish the account. The Board in its 2006 rates decision (EB-2005-0001) commented about some of the considerations that should apply when it is asked to consider disposition of costs relating to an appeal of a Board decision. Specifically, the Board stated:

> The rate structure in Ontario is predicated on a just and reasonable standard. Where a utility acting in good faith regards a Board decision to be unsound, it should be open to bring a Judicial

> Review action, and to have prospect of recovery of the associated costs.

In addition, the Board also had the following to say in that decision about determining the prudence of expenditures for appeals:

> In our view, the question of the prudence of the expenditure is not dependent on the success or failure of the review pursued by the Company; nor is the primary consideration whether the aspect appealed from inures to the benefit of the shareholder or the ratepayer. The determination of the prudence of the expenditure will turn on the reasonableness of the grounds for the review, the reasonableness of the costs incurred, including the relationship of the costs incurred to the likely outcome (which includes such intangibles as precedent, clarification of the law and corporate reputation), and the extent to which the Company can show that it prosecuted its case diligently and efficiently.

The Company submits that it clearly meets all tests which the Board stated are appropriate during its consideration of costs incurred by the Company on an appeal of a Board decision.

First, in respect of the Alliance Vector Pipeline disallowance by the Board, the amount was significant, being approximately $11 million. The appeal did not involve a frivolous amount.

Second, the Company was successful on its appeal to the Divisional Court and that this is clear evidence of the reasonableness of it undertaking the appeal. It also confirms that the Company acted in good faith launching the appeal. While the Company agrees with the Board that the prudence of appeal expenditures is not dependent on the success or failure of the review, the fact that an independent judicial body agreed with the Company, is irrefutable proof of the reasonableness of the grounds for the review and hence the appropriateness of it launching the appeal.

Third, as to whether the costs incurred were reasonable, the Company is not seeking to recover any of the costs it incurred associated with the original appeal to the Divisional Court.

Fourth, there can be no question about the appropriateness of the Company recording the costs which it did in this deferral account. In its EB-2005-0001 Decision with Reasons, the Board specifically stated that the Company should apply for a new deferral account to capture the costs associated with the Judicial Review process at Divisional Court and any appeal proceedings thereafter.

Fifth, all of the amounts recorded in this account relate to legal fees and disbursements invoiced by the Company's counsel on the appeal, Fraser Milner Casgrain, who were also counsel on the original Divisional Court appeal. Accordingly, there were no costs incurred which would be associated with retaining and educating new counsel.

Sixth, all of the legal bills that were received would have been directed through the Company's Associate General Counsel, and then they were subsequently reviewed to determine that the hours and dates spent were sufficient in the context of the proceedings. Counsel on the appeal, Fraser Milner Casgrain, were in fact the same counsel that acted for the Company in the proceedings before the Board where the Alliance Vector costs were disallowed. None of the costs associated with Fraser Milner Casgain's representation of the Company at that Board proceeding were disallowed.

Seventh, the OEB's costs for its leave to appeal the Divisional Court decision and the subsequent appeal of the Divisional Court decision are being recovered from Ontario ratepayers through the OEB's assessment authority. It only seems fair and reasonable that the Company also recover its costs from ratepayers for responding to the proceedings initiated by the Board.

CCC argued that the Company should not be allowed to recover any of the $529,000 amount claimed. In the alternative, it should recover no more than $30,000. In support of this alternative amount, CCC noted that the Board's principles were enunciated before Enbridge's application for leave to the Supreme Court and therefore these principles do not apply. Rather, section 40 of the *Supreme Court Act* specifies the criteria that the Supreme Court of Canada applies whether leave will be granted and Enbridge did not meet the Court's criteria. The Board must decide on the reasonableness of Enbridge's costs with that in mind, especially since Enbridge did not file any evidence so that the Board would be able to judge the merits of that application. Moreover, the $82,000 in costs associated with that application for appeal “seems grossly disproportionate”. With respect to the $445,000 in claimed costs for responding to the Board’s application for leave to appeal to the Ontario Court of Appeal and the appeal itself, CCC termed the claim “grotesque”.

IGUA and VECC noted that they support CCC’s position with respect to this matter.

Schools submitted that the Company’s evidence is insufficient to demonstrate the reasonableness of the costs claimed, which the Company was required to do. Even allowing for preparation time, $529,000 (before interest) for a matter that took one day of argument at the Court of Appeal is excessive.

The Board does not question the Company’s proposal to recover costs associated with its participation to the Ontario Court of Appeal and its application to the Supreme Court of Canada. Neither does the Board question the existence of records to support this claim. It is not expected that the Company file such detail as part of its pre-filed evidence. While the onus is on the utility to prove its case, it was open to the parties to ask for supplementary information through the interrogatory process or during the hearing when the issue was canvassed. Parties did not develop that additional record. It is not reasonable to now fault the Company for an “insufficient” record. On the record before it, the Board finds it appropriate that the recorded balance in this account should be recovered by the Company, as proposed.

2005 and 2006 Gas Distribution Access Rule Costs Deferral Accounts (GDARCDA)

The amounts recorded for the 2005 and 2006 GDARCDA are $435,200 and $7,985,400, respectively. These amounts are to be capitalized. The amounts recorded in these accounts relate to the costs incurred by the Company to ensure that it is GDAR compliant.

The Board and all participating parties have been aware over the years that the Company would incur significant costs to meet the requirements of GDAR. It has only been over the course of the last year where enough detail has been driven out to the point where the Company could start to look at how it would have to re-engineer its business processes and modify its computer systems to accommodate the rule.

The project has been governed by a Steering Committee, in addition to an external risk manager, and a senior representative from both the Company's IT and Regulatory groups.

There has been a Project Manager in place throughout who reports to the Steering Committee and who also manages external resources working on the project. The Company has had a detailed project plan in place, which includes work plans and project milestones which form the basis of the project's budget.

The costs recorded in the 2006 deferral account plus the costs that the Company will incur in 2007 to be compliant by June 1st, in total will be about $1.7 million lower than the initial estimates provided.

CCC supported the clearance of the accounts, on the assumption that the costs are entirely related to Service Transaction Requests, but noted that this support is in no way an acceptance of the reasonableness of the GDAR costs that will be incurred in the future.

IGUA noted that it supports CCC's position with respect to this matter.

VECC stated that it has no reason to dispute the prudence of the costs incurred in this account. VECC requested that the Board require the inclusion of a representative of small volume customers in the remaining GDAR implementation stages as the small volume customers were not directly engaged in the process, though they will bear the cost consequences.

On the basis of the evidence, the Board has no reason to doubt that the reported balances are not related to Service Transaction Requests and that they are not reasonable. The Board accepts the disposition of the reported balances as proposed by the Company.

With respect to VECC's request for inclusion of a representative of small volume customers in the remaining GDAR process, the Board notes that GDAR is an independent initiative from this proceeding and VECC may make this request in that process.

CAPITAL STRUCTURE AND COST OF CAPITAL

Issue 4.2 was whether the Company's proposed costs for its debt and preference share components of its capital structure appropriate. No party took issue with the Company's evidence, nor does the Board.

This section therefore addresses the remaining issue related to capital. Specifically, Issue 4.3 read "Is the proposal to change the equity component of the deemed capital structure from 35% to 38% appropriate?" There was no settlement of this issue.

The Company' evidence is that it has suffered a dramatic decline in its financial strength. As a result, Enbridge's ability to raise new long term debt has been constrained and there is a real risk of a further downgrade in the Company's credit rating. An increase in its common equity ratio from 35% to 38% is necessary to restore the Company's financial integrity to a level that will allow it to sustain access to long term capital on reasonable terms. An increase in the equity thickness to 38% is also warranted by reason of higher business risks now faced by Enbridge. This latter evidence was given on behalf of Enbridge by Paul Carpenter of the Brattle Group.

Enbridge attributed the erosion in its financial strength to a steady decline in the allowed ROE that has outpaced the effect of declining interest rates on the Company's financing costs. Long term debt is issued at fixed rates for fixed terms and the rates payable on this embedded debt do not change as interest rates decline and the ROE goes down. As ROE declines, and the cost of long term debt remains fixed until debt maturities occur, the Company's ability to cover the interest on the debt is limited.

A measure of a company's financial strength is the Earnings Before Interest and Taxes (EBIT) interest coverage the ratio which is the quotient of the company's earnings divided by its interest expense. Enbridge noted that lower interest rates lower the ROE immediately but it takes time for the interest expense element of the Company's interest coverage ratio to decrease as interest rates decline, because Enbridge cannot refinance all of its long term debt in every year. The result is a lower EBIT coverage ratio which diminishes the Company's ability to issue new debt.

According to the Company, its weather-normalized EBIT interest coverage declined from a ratio of 2.38 in 1993 to 2.10 in 2006. Enbridge's margin above 2.0 times coverage for each of the years from 1993 to 2006 declined from $48.0 million in 1993 to $16.8 million in 2006.

Specifically, the Company noted that its existing trust indenture prohibits the issuance of new term debt if Enbridge's actual legal entity EBIT interest coverage ratio for any consecutive 12 month period out of the last 23 months does not exceed 2.0 times. In order for Enbridge to stay in compliance with the financial covenants in the trust indenture, the margins above normalized utility EBIT 2.0 times coverage must allow room to accommodate the effect on the Company's financial results of unexpected swings in the weather. EBIT margin above 2.0 times interest coverage had declined to $16.8 million by 2006. During the period since 1993, the average annual impact of weather on the utility's EBIT has been $35.0 million. The margin above 2.0 times interest coverage of $16.8 million is significantly less than what the Company needs to accommodate an average swing in the weather.

Enbridge testified that it must maintain a normalized allowed utility EBIT interest coverage ratio of at least 2.2. The requested equity ratio of 38.0% marginally achieves this minimum target. Given the magnitude of volatility in its earnings, the Company noted that even with 38% equity thickness and the minimum coverage at 2.2 on a weather-normalized basis, there is no assurance that Enbridge will always meet the new debt issuance test.

The Company indicated that, because of the considerably warmer than normal weather it experienced in 2006, it would not be able to meet the interest coverage test for any 12 month period that includes the period January-March 2006 to enable it to issue new debt. Actual weather in the first quarter of 2006 was considerably warmer than forecast. The warmer weather in the first quarter of 2006 alone reduced Enbridge's EBIT by

$33.3 million and the negative impact on its earnings because of weather was $57.7 million in impact for the full 2006 year.

The impact of a lower ROE in 2006 combined with actual results for January 2006 to March 2006 caused a significant decline in the actual interest coverage ratio, such that, as of January 2007, the ratio is about 1.85 times to 1.95 times depending on the 12 month period chosen from the previous 23 months. The Company noted that its ability to meet the new debt issuance test through 2007 and beyond will depend on the equity thickness allowed by the Board in this case and actual operating results for 2007, including any weather variances.

It is Enbridge's judgment that the ultimate costs to the ratepayer will almost certainly be higher if the Company's credit quality is allowed to decline further. Costs will rise due to constraints on accessing the long term debt as there is a risk for credit rating downgrades leading to suboptimal financing options.

Enbridge's evidence was supplemented by the evidence of Paul Carpenter of the Brattle Group. Dr. Carpenter provided evidence about changes in business risk that have occurred since 1993, when the appropriate level of equity thickness for Enbridge was last considered by the Board. Dr. Carpenter contends that equity investors would consider investment in Enbridge to be more risky than it was in 1993 because of a) changes in the commodity market for natural gas, b) increased risk of bypass, c) new gas-fired generation, and d) uncertainty as to the future rate regulation framework. Dr. Carpenter's remedy is also an increase in the common equity thickness but from the Company's business risk perspective, independent from the credit quality considerations advanced by the Company.

Dr. Booth, on behalf of CCC, IGUA and VECC, testified that Enbridge's current 35% allowed common equity is reasonable, if not generous. In support of that conclusion, Dr. Booth testified that Enbridge's short-term business risk is low and lower than that of Union Gas whose common equity thickness was negotiated at 36%. Furthermore, Enbridge's credit ratings have been quite stable, placing the Company among the premium group of regulated utilities in Canada.

Enbridge provided comparisons of its currently approved equity level to the equity levels in other Canadian jurisdictions and noted that it is apparent that Enbridge's equity ratio has fallen out of line during a period of years when the appropriate level of equity for the Company has not been considered by this Board, but equity levels for other Canadian utilities have been increasing.

Enbridge noted that Professor Booth's view of appropriate equity levels is not shared by Canadian regulators and is not reflective of what actually happens in the Canadian capital markets. According to Enbridge, there is clear trend in regulatory decisions towards higher levels of equity for Canadian regulated utilities. Professor Booth's views about debt/equity ratios of Canadian regulated utilities run counter to this trend and his recommendations are not aligned with what is actually happening in Canadian capital markets.

Positions of the Parties

Board Staff noted the testimony by the Company's witness that Enbridge's business risk is "pretty similar" to that of Union Gas' and that Union Gas' common equity was settled at 36%. On this basis, and on the basis that the Board has decided that a consistent debt-equity capital structure be implemented among electricity distributors, Board Staff stated that a common approach may be merited for the gas utilities and that a 36% common equity for Enbridge may be warranted.

Union Gas submitted that the OEB must consider capital structure in the context of well settled principles governing return on investment to equity holders. This includes a consideration of comparable risk, ensuring financial integrity and the attraction of capital on reasonable terms. Business risks have increased for utilities in Canada and interest coverage ratios are barring Ontario utilities from access to capital markets at a time when infrastructure investment is as important as it has ever been. Union Gas also noted that there has been a trend to increased equity thickness awarded to energy utilities across Canada.

CCC submitted that Enbridge has not demonstrated that it requires an equity component of 38%. CCC argued that Enbridge has not demonstrated that either its business risk or its regulatory risk has increased. CCC noted Dr. Booth's evidence that Enbridge's inability to access debt in the form of unsecured Medium Term Notes (MTN), is only temporary. It has been the result of the combination of warmer weather and decline in interest rates which affect return on equity pursuant to the Board's adjustment formula. As existing debt issues mature and are replaced with new ones at current interest rates, Enbridge's interest coverage ratio will naturally increase. It would not make sense to implement a longer term costly solution to address a temporary problem. CCC submitted that Enbridge has not demonstrated that its credit ratings are in jeopardy. CCC also submitted that Enbridge has effectively put itself into this temporary situation by flowing amounts to its parent during 2006 beyond what was approved by the Board. CCC noted that Union Gas has an equity level of 36% and that Enbridge's own witness, Dr. Carpenter, acknowledged that Union Gas is riskier than Enbridge. CCC noted that while it is acceptable for the Board to consider whether or not Ontario distributors should be subject to weather risk, this was not on the issues list in this proceeding. Had this been the case, parties, including Union Gas, may have filed evidence. It would be premature for the Board to make this determination in this case without the benefit of an appropriate forum for this issue to be aired.

IGUA argued that Enbridge's business risks have always been and remain low. Any recent changes in business risks facing Enbridge are immaterial and do not justify an equity ratio greater than 35%. IGUA argued that an equity ratio greater than 35% cannot be justified by comparing Enbridge to other utilities. Regulatory decisions of other tribunals do not assist Enbridge in satisfying the threshold requirement of objective and independent evidence that a material change in risk has occurred. Existence of weather risk cannot prompt an increase in Enbridge's equity ratio. The regulatory tools which should be used to respond to the weather risks Enbridge faces are the rate design measures and/or the removal of the weather risk from the Company through a deferral account as it is done by the British Columbia Public Utilities Commission. However, any consideration by the Board of a weather adjustment mechanism should take place in the context of a generic proceeding. With respect to

Enbridge's claims regarding the challenges in interest coverage and access to debt capital, IGUA argued that this is only temporary and will disappear as the Company's long term debt issues mature. IGUA termed Enbridge's proposal as a "base year stuffing" measure before the long-term incentive regulation is implemented. IGUA argued that Enbridge's actual normalized EBIT interest coverage ratio for the "stand alone" utility is more than adequate. IGUA particularly noted that the exclusion from normalized actual earnings of the sums paid by Enbridge to its parent and affiliates in excess of Board-approved amounts.

Energy Probe supported IGUA's arguments. It further noted that the Company is far from facing a crisis. The Company's proposal is in effect a request for costly insurance, to the tune of $9.5 million annually, which does not represent the least overall cost solution.

VECC submitted that Enbridge's problem of access to the MTN market is temporary and should be addressed by short-term solutions that provide access to needed capital until existing debt is retired. The best and least cost solutions according to VECC are either using commercial paper swapped into medium term debt or a medium term preferred share issue. Either one of these solutions would allow Enbridge to access capital on reasonable terms until its high coupon debt gets refunded over the next few years. Since 2008 is likely to be the first year of incentive regulation, establishment of a deferral account would allow Enbridge the opportunity to recover any prudently incurred incremental costs of maintaining access to the MTN market. In VECC's view, Board Staff's regulatory symmetry with Union Gas is not appropriate, since it does not take into account the fact that Enbridge has lower business risk than Union Gas, or that Union Gas' equity was the result of a negotiated settlement.

Board Findings

The Company's proposal for a thicker common equity in the deemed capital structure is grounded on business and financial risk considerations as well as its deemed common equity has fallen out of line with other Canadian utilities.

While the Board is of the view that Enbridge has presented credible evidence of a trend among Canadian regulators in finding thicker common equity for utilities, the Board does not generally find a comparison of Enbridge's common equity ratio with those in other jurisdictions to be necessarily determinative of the issue. An applicant must still satisfy the threshold requirement of independent evidence that material changes have occurred to justify a thicker common equity. Moreover, the hazard in doing so is that it engages issues of oversimplification and circularity, which downgrade the specificity that is required to make decisions pertaining to a particular utility. With those caveats, the Board nevertheless is mindful of the increasing trend and has factored this in its deliberations.

There is some value in considering evidence on the relative risk profile of the two large Ontario gas utilities. While Union's current 36% common equity was the result of a negotiated settlement, Enbridge's proposal for a 38% common equity level is materially higher than Union's, which is not consistent with the relative business risk profile of the two utilities. In fact, there was no dispute that Enbridge is a lower risk utility than Union Gas.

The Company claims that its business risk has increased over the last 10 to 15 years on several fronts. These are addressed below.

The Board agrees with parties who argued that the regulatory and legislative risks which Enbridge currently faces are not greater than they were last year or in prior years, at least not materially greater.

With respect to the risk of bypass noted by the Company, the Board is of the view that the Company has under-estimated the risk mitigation through the development and approval for rate options to specifically address the need of gas fired generators and mitigate any potential for bypass risk.

With respect to the claim by Enbridge that incentive regulation could lead to increased regulatory risk, Enbridge has operated under a performance based mechanism before. Moreover, the tenet behind an incentive regime is that the utility can reap the benefits of newly found efficiencies and it is only upon rebasing that these efficiencies will be shared with or passed on to ratepayers. From these perspectives, an incentive rate reqime is not necessarily an arrangement that negatively affects the risk of the utility.

From the market reports that were filed in the proceeding, there is no evidence on balance that Enbridge no longer enjoys a reasonably stable legislative and regulatory environment.

Even if there was some recognition of increased business risk in the totality of the Company's arguments, this must be weighed against other positive considerations. For example, the Company's evidence indicates that customer growth continues to be strong and natural gas remains the predominant fuel of choice in Enbridge's franchise area. Enbridge's customer base is consistently growing year after year. The Board does not see this as indicative of increased business risk.

In the result, the Board finds that the evidence presented by Enbridge does not warrant an increase in the common equity thickness to 38% on account of increased business risk, but the evidence on the trend of common equity thickness suggests that the 35% level in existence since 1993 should be considered as a floor.

This leaves the Company's proposal to also be evaluated on the basis of its claimed inability to raise capital, at least on reasonable terms.

The Board accepts that decreases in interest rates in 2006 have impacted the Company's EBIT adversely as there is a lag between the reduction in ROE and reductions in the total debt interest liability. The warmer than normal weather in 2006 contributed to the impact on EBIT. To worsen matters, the Company has paid out considerably more to its affiliates than what was reflected in the Board's 2006 revenue requirement decision. Whether or not the Company will be able to raise long term debt in the 2007 test year will very much depend on weather and its overall performance going forward.

The Board accepts that there may not be a practical way to circumvent the interest rate covenants in the current trust indenture. To alter these covenants would require agreement by current debt holders and this will likely come at a cost. To be clear, the Company is not suggesting that this would be a reasonable remedy. It is unfortunate that these covenants pose such a high restriction. The Board notes that the Company is considering ways by which the existing covenants may be replaced in the longer run. The Board encourages the Company to pursue this initiative.

The Board agrees with the many intervenors who argued that the problem is or may be temporary. On the assumption of a continuing low interest rate environment, as debt matures and is replaced the lower interest charges would provide some relief. If interest rates increase, the relief may be quicker. Relief may well even come from weather.

In any event, like many intervenors the Board is not convinced that the Company's proposed remedy to what is or may be a temporary problem represents the least cost solution. The common equity component of Enbridge's capital structure is and should be a matter that is reviewed infrequently. The Company's proposal to increase the common equity thickness from 35% to 38% carries an annual cost of about $10 million to ratepayers. In view of that substantial cost, the Board must consider other remedies.

In consideration of all of the above, and on balance, the Board finds an increase in the common equity thickness from 35% to 36% to be reasonable. While this finding should alleviate somewhat the financial pressure currently experienced by the Company, it alone might not fully address the immediacy of the problem, if the problem continues indeed to exist. The Company therefore might need to engage in financing alternatives other than issuing of long term debt in the shorter term. This may involve a number of market instruments that are available to the Company, if indeed the Company cannot issue long term debt when it needs it. The Company must also be more wary of the impact of excessive payments to its affiliates on EBIT.

The Company's evidence was that, in the period 1993 to 2006, the Company lost $107 million in EBIT due to warmer-than-forecast weather and that the average impact of weather in either direction on EBIT was $35 million, which is two times more than the $16.8 million currently reflected in rates according to the Company's evidence. The

Board is of the view that, given the large influence of weather on EBIT, this risk may need to be removed from the utility.

The Board recognizes that a move to removing weather risk from the Company is a decision that has implications for all regulated gas utilities regulated by the Board, and perhaps for electricity utilities as well. The Board considers this to be worthy of evaluation in the near future.

REVENUE TO COST RATIOS

The revenue to cost ratio compares the forecast recovery of revenues from each rate class, derived through the rate design process, to the allocation of forecast costs for each rate class, arrived at through the cost allocation process. A revenue to cost ratio for a rate class of unity means that the rate class is forecast to recover all of the allocated costs to that class.

The Company's pre-filed evidence set out the manner in which it initially proposed to allocate the proposed revenue requirement among customer classes. Issue 6.2 reads:

> Is the proposal to allocate revenue requirement between the customer classes and annually adjust the monthly customer charges and variable charges to recover the revenue deficiency reasonable?

Parties agreed on matters pertaining to the adjustments to the monthly customer charges and variable charges. The unresolved aspect of Issue 6.2 is described in the Settlement Proposal as follows:

> There is no agreement about the Company's proposal to allocate revenue requirement between customer classes. Some parties are concerned that the allocation of the 2007 revenue deficiency as proposed in the Company's evidence results in the collection of revenues greater than allocated costs from Rate 1 and Rate 6 customers based on the Company's filed Revenue to Cost ratios of 1.02 and 1.01 for these rate classes. These parties wish to explore the proposed 2007 revenue requirement allocation in light of the evidence and interrogatory responses on this issue. Other parties support the Company's revenue deficiency allocation and will oppose changes to it.

Appendix B to the Settlement Proposal sets out the Company's proposal for the recovery of the test year revenue requirement with assumed revenue deficiencies of $26 million and $82 million, which reflect the minimum and maximum revenue deficiencies that could result from the final Board decision in this case. Appendix B also sets out the revenue to cost ratios that would result for each rate class. In both scenarios, the revenue to cost ratios proposed by the Company for Rate 1 will be 1.01, which is the same as the Board approved in 2006. The revenue to cost ratios proposed for all other rates are 1.01 or less.

Appendix B also sets out the dollar amount of any over or under contribution by each rate class, relative to the costs allocated to that rate class. A portion of the over and under contribution for most rate classes relates to the phase-in of the allocation of upstream transportation costs on a volumetric basis (referred to as the phase-in of TCPL tolls). This phase-in, which was approved in the Company's 2005 rate case (EB-2003-0203), was to be completed over four years, so that the rate increase impact on large volume customers would not be too large in any one year. A corresponding impact of the phase-in is that associated over-contributions from Rates 1 and 6 have remained in place, at least in part, for four years while the under-contributions from large volume customers were phased out. The phase-in will be completed as of October 1, 2007. From and after that time, the actual amount of over or under-contribution for each rate class will no longer include any adjustment. All things being equal, the forecast revenue to cost ratios for Rates 1 and 6 will have decreased as the impact of the upstream transportation cost allocation adjustment is fully phased in.

The Company provided an illustrative example of how other rate classes would be impacted in the test year if $5 million of revenue requirement were shifted away from Rate 1 and recovered instead from the large volume rate classes. The effect of such a shift would be that, on a prospective basis from October 1, 2007, the rate increase for Rate 100 would move from 1.9% to 3.6%, the rate increase for Rate 145 would move from 1.6% to 8.0% and the rate increase for Rate 170 would move from 1.8% to 8.0%.

Whatever the ultimate revenue deficiency that the Board determines in this case, the Company has indicated that it will maintain revenue to cost ratios, and over/under contribution amounts by rate class, at approximately the same level as set out in Appendix B to the Settlement Proposal. The Company has also indicated that it will file, along with the draft final rate order in this case, a narrative explanation of the steps taken and adjustments made to arrive at final rates, and corresponding revenue to cost ratios.

Positions of the Parties

The Company asserts that its proposal is a fair and appropriate approach to the recovery of the revenue requirement from all rate classes. The approach is consistent with that taken and approved by the Board in previous years, where the revenue to cost ratio for Rate 1 has also been 1.01.

While the Company attempts to set revenue to cost ratios as close to 1 as possible, it also must take account of other rate design objectives. These objectives include rate stability, market conditions, maintaining competitive position, market acceptance, rate class characteristics and rate impacts on other rate classes. The Company also takes account of the revenue to cost ratios for each rate class from previous years and seeks to maintain similar ratios, on the assumption that the Board approved those ratios in previous years, and in order to avoid large rate swings in some rate classes which have corresponding impacts on others. While the Company seeks to keep revenue to cost ratios close to 1, the actual ratios are typically slightly different from 1, but within a reasonable band of tolerance so that there is no undue over or under collection from any particular rate class. The Company believes that it is important to retain some degree of flexibility with respect to revenue to cost ratios, so that the variety of applicable rate design objectives can be addressed. If the Company were required to maintain prescribed revenue to cost ratios, this flexibility would be lost. Moreover, a requirement to meet specified revenue to cost ratios could be very difficult to implement and maintain over time and, in some cases, may not be feasible.

If $5 million was shifted away from Rate 1, the level of rate increase to some rate classes would be less appropriate than the approach the Company advocates, particularly in the case for customers on interruptible Rates 145 and 170 who have dual fuel capability. In the event of large increases to those rates, affected customers may switch away from gas altogether, leaving other customers worse off as a result.

IGUA, Transalta and OAPPA supported the Company's proposed revenue to cost ratios as reasonable and falling within tolerable limits.

CCC noted Enbridge's testimony that it will be more explicit that it has been in the past regarding the determination of final rates as part of the Rate Order and in CCC's view this would be helpful.

VECC expressed concern with the proposal to maintain a revenue–to-cost ratio greater than one for Rate 1 customers in the test year. If the proposal is accepted and not corrected prior to setting base rates for a multi-year incentive regulation program, this over-contribution would be embedded for the duration of such scheme.

Board Findings

The Board notes that the proposed revenue to cost ratio for Rate 1 is actually 1.006, which has been rounded to 1.01. The Board considers this to be within a reasonable band of tolerance given the many other considerations and factors that enter into striking rates for each class, which they were enumerated by the Company. Requiring the Company to maintain strict 1.0 revenue to cost ratios for each class will remove the flexibility that may be needed to accommodate those other considerations and factors.

VECC's concern is that the settled revenue to cost ratio for Rate 1 in this proceeding will be fixed for the next six years under planned incentive regulation. The Board agrees with the Company that the cost drivers that will play into revenue to cost ratios over the next six years cannot be known now and that there is a pending rate proceeding to deal with rate-setting issues under incentive regulation.

The Board therefore accepts the Company's proposed revenue to cost ratios, and these shall be used to calculate proposed rates reflecting the final revenue requirement reflecting the Board's findings in this proceeding.

The Board notes the Company's commitment, as stated in its argument-in-chief , that it will file, along with the draft final rate order in this case, a narrative explanation of the steps taken and adjustments made to arrive at final rates, and corresponding revenue to cost ratios.

RATE IMPLEMENTATION

In regard to Issue 9.1 (How should the Board deal with any revenue deficiency applicable from January 1, 2007 to the date that the Board's decision is implemented?), the Company is seeking approval for the full recovery in rates during the 2007 test year of the full amount of revenue deficiency awarded by the Board in its final decision in this case. The Settlement Proposal in respect to this issue provided that:

> All parties agree that for rate implementation purposes only, the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. GEC's and Pollution Probe's agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result Issue 3.2. Schools' agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result of Issue 9.1.

and parties, except for Schools, agreed that:

> …..the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. Parties agree with and support the Company's proposal to recover the full $26.0 million through (i) increased annualized rates for the remainder of the test year; and (ii) the use of a rate rider over the nine remaining months of the test year to recover the remaining balance of the $26.0 million. Intervenors agree that no issue or objection will be raised around whether any part of this $26.0 million is unrecoverable because it relates to the time period between January 1, 2007 and April 1, 2007.

> There is no agreement as to whether or how the Company can recover any revenue deficiency in excess of $26.0 million.

The Board issued an interim rate order on March 26, 2007 which allowed for the recovery of $26 million in revenue deficiency by way of interim rates effective January 1, 2007 and implemented April 1, 2007, along with a rate rider to apply from April 1 to December 31, 2007. The amended rates will recover approximately $21 million in deficiency over the period April 1, 2007 to December 31, 2007, and the rate rider will recover an additional $5 million.

The Company proposes to recover any incremental revenue deficiency (that is any amount that is more than $26 million) through amended base rates and an additional rate rider to apply to the end of the test year. In the event that the Board's final decision results in a total revenue deficiency that is less than $26 million, the Company will adjust its rates accordingly.

The Company also proposes to clear all approved deferral and variance account balances on a one-time basis to rates. As set out at Issue 3.13 of the Settlement Proposal, the impact of this clearance for accounts, other than the 2006 Purchased Gas Variance Account (2006 PGVA) be a credit of approximately $23 million in favour of ratepayers, with the final amount adjusted to reflect the Board's decision in respect of the deferral and variance accounts that were reviewed and tested during the hearing. At the same time, the Company would also clear the outstanding balance in the 2006 PGVA as a one time adjustment, which will result in an offsetting debit of approximately $20 million.

As the Company's test year commenced January 1, 2007, the only implementation issue was the effective date of the new rates.

Positions of the Parties

The Company argued that circumstances outside its control prevented a timely filing of its application, including extenuating factors associated with the date of the 2006 test year Board decision and the complicated and lengthy consultative processes which were supported by all intervenors and led to positive results.

CCC stated that although there were avoidable delays caused by Enbridge, the timing of the hearing was not solely related to these delays. A number of consultatives were ongoing and there were Board scheduling issues. The Board should allow full recovery of the found revenue requirement in this case but should state as a matter of policy that may be financial consequences in the future if the delays are caused by the Company.

IGUA stated that although the Company did not initiate its application as promptly as it might have, given some extenuating circumstances in this particular case, including the consultatives, the Company should not be deprived of that portion of the agreed upon deficiency of $26 million which normally would have been recovered between January 1, 2007, and April 1, 2007. IGUA also stated that it accepts that any revenue deficiency over the agreed upon $26 million should be recovered through a rate rider to December 31, 2007, but only if in its view the impacts on large volume customers were reasonable following the Board’s Decision. Otherwise, IGUA stated that it reserves the right to argue for a lower rate rider that would extend beyond December 31, 2007.

VECC supported recovery of the remaining revenue deficiency on a prospective basis but, consistent with its earlier argument, the recovery from customers should correct for the over-contribution from Rate 1 customers.

Schools referred extensively to Enbridge’s testimony and argued that the Company could have filed its application earlier, therefore it should be responsible for causing the retroactivity. Schools suggested that the $5 million of the $26 million agreed upon deficiency could have been recovered from January 1, 2007 to March 31, 2007, and therefore should not now be recovered. With respect to any additional revenue deficiency to be found, the portion of such additional deficiency that would have been recovered from January 1, 2007 to the date of implementation of the new rates should not be recovered from ratepayers.

Board Findings

The prospect of retroactivity is always problematic for the Board. To be clear, having declared the Company's interim effective January 1, 2007, the effective date for the new rates in not a legal issue in this case. The Company can in this case request and the Board can grant an effective date of January 1, 2007. Rather, the issue of retroactivity is one of rate impacts and customer acceptability. The Board has stated numerous times that it does not endorse retroactivity, regardless of how the monies are recovered. The Board has attempted to work with the utilities and other parties so that retroactivity can be avoided. Some progress was made in recent years but now that progress appears to have been stalled.

The Board accepts, as many parties do, that there were extenuating circumstances in the past year which contributed to the Company's late filing. The Company had to comply with new minimum filing requirements, its evidence had to be in new formats, and the Company was engaged on a number of other important files before the Board. Also, there were a number of financially significant and complex items that were the subjects of several consultatives. However, while the use of the consultatives bore fruit on certain issues, their conclusions were not timely. Some of the consultatives did not complete their deliberations in time for the commencement of the hearing with the result that the hearing was postponed a number of times. The responsibility for that should not rest only with the Company. In the future, the Board expects parties to conclude any consultatives in adequate time for the hearing to commence when scheduled.

Recognizing these unique circumstances, the Board will not penalize the Company for the lateness of its filing, the commencement of the hearing and the resultant retroactivity. The Board expects the Company to endeavour to bring its filing cycle so that retroactivity can be avoided in the future. The Board expects all parties to act in a positive fashion to avoid retroactive ratemaking in the future.

The Board accepts the Company's proposals to implement recovery of the full revenue deficiency for the 2007 test year arising from this decision.

The Board also accepts the clearance of the balances in the deferral and variance accounts as proposed by the Company except in circumstances where the Board had made different findings in this decision.

Also, the Company in its Argument-in-Chief proposes that the Board include clearance of the 2006 PGVA balance in its decision regarding the disposition of deferral accounts tested during the hearing. The Board notes that the 2007 Settlement Proposal (p.32 of 47) indicates that parties agreed that Enbridge is not seeking to clear in the test year, certain balances, of which one was the 2006 PGVA, and these would be addressed by the Board in the future. The Board anticipates that the next QRAM application may be an opportune time for the Board to consider this matter.

The Board directs the Company to file a draft rate order reflecting the Board's findings, with an implementation date that in the Company's view would be more appropriate. Intervenors wishing to comment on the draft rate order shall file their submissions within 7 days from the Company's filing.

The Company shall include in that filing appropriate documentation in support of its draft rate order, including updates to the "N1, Tab2" series of exhibits.

COST AWARDS

On day 16 of the oral hearing the panel directed eligible parties to file their costs claims, for all costs up to and including April 13, 2007, by May 4, 2007.

Parties who intend to claim cost awards for activity subsequent to April 13, 2007, shall submit their cost claims by July 26, 2007. A copy of the cost claim must be filed with the Board and one copy is to be served on Enbridge. The cost claims must be done in accordance with section 10 of the Board's Practice Direction on Cost Awards.

Enbridge will have until August 9, 2007 to object to any aspects of the costs claimed. A copy of the objection must be filed with the Board and one copy must be served on the party against whose claim the objection is being made.

The party whose cost claim was objected to will have until August 16, 2007 to make a reply submission. Again a copy of the submission must be filed with the Board and one copy is to be served on Enbridge.

DATED at Toronto, July 5, 2007.

Original signed by

Gordon Kaiser
Vice Chair and Presiding Member

Original signed by

Paul Vlahos
Member

Original signed by

Ken Quesnelle

Member

APPENDIX A

ENBRIDGE GAS DISTRIBUTION INC.

2007 TEST YEAR

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0034

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

JULY 5, 2007

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

THE PROCEEDING

On September 7, 2006, the Board issued a Notice of Application which was published and served in accordance with the Board's direction.

The Board issued Procedural Order No.1 on October 4, 2006, establishing the procedural schedule for all events prior to the oral hearing, as well as the Issues List for the proceedings. These scheduled events included:

- Issues conference on October 10, 2006;
- Issues Day on October 12, 2006;
- Written interrogatories to the Applicant by October 23, 2006;
- Written interrogatory responses from the Applicant by November 9, 2006;
- Intervenor evidence filed by November 14, 2006;
- Written interrogatories on Intervenor evidence by November 21, 2006;
- Responses to written interrogatories on Intervenor evidence by December 5, 2006;
- Intervenor Conference on December 7, 2006;
- Settlement Conference beginning December 11, 2006;
- Settlement Proposal by January 4, 2006;

- Board review of Settlement Proposal on January 9, 2006.
- Oral Hearing beginning on January 11, 2007

On Issues day, the Board heard submissions from Enbridge Gas Distribution Inc. (“Enbridge”), Pollution Probe Foundation (“Pollution Probe”), Industrial Gas Users Association (“IGUA”), Union Energy LP, the Consumers Council of Canada (the “Council”), Direct Energy Marketing Limited (“Direct Energy”), Superior Energy Management (“SEM”), TransAlta Energy Corp (“TransAlta”), Coral Energy, Green Energy Coalition (“GEC”), Heating, Ventilation and Air-Conditioning Coalition Inc. (“HVAC”), Energy Probe Research Foundation (“Energy Probe”), School Energy Coalition (“Schools”), the Vulnerable Energy Consumers Coalition (“VECC”), and the Low-Income Energy Network (“LIEN”).

On October 20, 2006, the Board issued Decision and Procedural Order No. 2, dealing with the status of three parties as intervenors and eligibility for costs, the question of the Board’s jurisdiction regarding rate affordability programs, and the approved Issues List.

Procedural Order No. 3, issued November 6, 2006, involved a Motion brought forward by LIEN for orders to:

- Extend the dates to serve and file interrogatories on the Applicant, and to file its Intervenor evidence, by 30 and 60 days respectively from the date of Board decision on their Motion;
- Confirm LIEN’s eligibility for full cost awards, including newly raised issues

The Board heard LIEN’s Motion on November 17, 2006.

Procedural Order No. 4, issued November 29, 2006, made the following schedule changes:

- Written interrogatories on Intervenor evidence by November 24, 2006;

- Responses to written interrogatories on Intervenor evidence by December 8, 2006;

- Oral hearing to commence January 22, 2007;

- A provision for the treatment of certain interrogatory responses as "Proposed Confidential Undertakings" with objections to such course to be filed by December 4, 2006; EGD required to file any reply submissions by December 6, 2006;

- Settlement Proposals arising from the Settlement Conference to be filed with the Board no later than January 12, 2007

On December 20, 2006, the Board issued Decision and Procedural Order No. 5, which indicated that the rate affordability issue brought forward by LIEN would not be heard in the EB-2006-0034 proceeding, and declared rates, as approved in EB-2006-0288, interim effective January 1, 2007. The Board's decision was issued on April 26, 2007 where the majority of the panel found that the Board does not have jurisdiction to hear the rate affordability issue brought forward by LIEN.

On December 27, 2006, the Board issued Procedural Order No. 6, which set dates for a technical conference regarding Open Bill Access, involving Board Staff, Intervenors and Enbridge Gas Distribution Inc. The technical conference was held on January 10, 2007.

Decision and Procedural Order No. 7, issued January 12, 2007, provided the Board's finding regarding confidential treatment of certain responses to interrogatories.

On April 16, 2007, the Board issued Procedural Order No. 8, regarding the status of Issue 3.6, (Corporate Cost Allocation Methodology) given the filing of new evidence on February 14, 2007. The Order set Issue 3.6 to a separate phase in this proceeding.

The following parties filed written evidence with the Board:

- Eric Hoaken on behalf of Direct Energy;
- David MacIntosh on behalf of Energy Probe;
- John DeVellis on behalf of HVAC;
- Paul Manning on behalf of LIEN;
- Michael Buonaguro on behalf of VECC, the Council, and IGUA

PARTICIPANTS AND REPRESENTATIVES

Below is a list of participants and their representatives that were active either at the oral hearing or at another stage of the proceeding. A complete list of intervenors is available at the Board's offices.

Board Counsel and Staff	Michael Millar Richard Battista Edik Zwarenstein Colin Schuch Rudra Mukherji Khalil Viraney
Enbridge Gas Distribution Inc.	Fred Cass Patrick Hoey David Stevens Dennis O'Leary Robert Bourke
Pollution Probe	Murray Klippenstein Jack Gibbons Basil Alexander
Union Energy Limited Partnership ("Union Energy LP")	Kirsten Crain
Union Gas Limited ("Union")	Patrick McMahon Michael Penny

Industrial Gas Users Association ("IGUA")	Peter Thompson Vince DeRose
Consumers Council of Canada ("the Council")	Robert Warren Julie Girvan
Direct Energy Marketing Limited	Dave Matthews Eric Hoaken
Superior Energy Management ("SEM")	Elizabeth DeMarco
TransAlta Cogeneration LP, TransAlta Energy Corp ("TransAlta")	Elizabeth DeMarco
Ontario Energy Savings Corp	Nola Ruzycki
Green Energy Coalition	David Poch Kai Millyard
Heating, Ventilation and Air-Conditioning Coalition Inc. ("HVAC")	John De Vellis
Ontario Association of Physical Plant Administrators ("OAPPA")	Valerie Young
TransCanada Pipelines	Murray Ross Jennifer R. Scott Bernard Pelletier
Energy Probe Research Foundation ("Energy Probe")	David Macintosh Tom Adams Randy Aiken
School Energy Coalition ("Schools")	Jay Shepherd Bob Williams
Natural Gas Specialist	Jason F. Stacey
Accenture Business Services for Utilities Inc. ("ASBU")	Robert Howe
Low-Income Energy Network ("LIEN")	Paul Manning
Coral Energy Canada Inc. ("Coral")	Elisabeth DeMarco

CustomerWorks LP (“CWLP”)	Margaret Sims Hilary Clark
Vulnerable Energy Consumer’s Coalition (“VECC”)	Michael Buonaguro Michael Janigan Roger Higgin

WITNESSES

There were 51 company employees listed as witnesses by Enbridge Gas Distribution Inc. as part of their filed application. The following is a list of these participants:

Linda Au	Capital Budget Supervisor
John W. Bayko	Director, Operations Services
Glenn W. Beaumont	Vice President, Engineering & Information Technology
Mark Bergman	Senior Analyst, Economic & Market Analysis
Robert Bourke	Manager, Regulatory Proceedings
Bradley Boyle	Treasury Project Leader
Michael Brophy	Manager, DSM & Portfolio Strategy
Irene Chan	Manager, Volumetric Analysis and Budgets
David B. Charleson	Director, Energy Policy and Analysis
Susan Clinesmith	Manager, Business Markets
Jackie Collier	Manager, Rate Design
Anne Creery	Manager, Customer Care Operations
Kevin Culbert	Manager, Regulatory Accounting
Joel Denomy	Supervisor, Economic and Market Analysis
Jackie Eliason	Manager, Finance

Robert Fox	Chief Engineer, Engineering
Tanya M. Ferguson	Manager, Customer Care Financial Administration
Malini Giridhar	Manager, Rate Research and Design
Barry Goulah	Manager, System Measurement
Paul Green	Director, Market Development
Jane Haberbusch	Director, Human Resources
Patrick J. Hoey	Director, Regulatory Affairs
John Jozsa	Manager, Tax Services
Anton Kacicnik	Manager, Cost Allocation
Sagar Kancharla	Manager, Financial and Economic Assessment
D. A. Kelly	Manager, Operational and Capital Budgets
Narin Kishinchandani	Chief Accountant
Vivian Krauchek	Manager, Gas Supply
Thomas J Ladanyi	Manager, Budgets and Planning
Kerry Lakatos-Hayward	Manager, Business Development & Strategy
Douglas Lapp	Chief Safety Officer
Lee Liauw	Manager, Scorecard & Capital Appropriation
Gerry MacDonald	Director, NGV Business Development
Andrew Mandyam	Manager, CIS Program Operations
Catherine McCowan	Manager, Operations Service
Steve McGill	Manager, Strategic Projects & market Analysis
Michael Mees	Director, Customer Care
W. Robert Milne	Manager, Distribution Planning

Stuart Murray	Manager, Financial Assessment
Byron Neiles	Vice President, Legal Regulator & Public Affairs
Barry Remington	Manager, Property Taxes
Norman Ryckman	Group Manager Business Intelligence and Support
Jody Sarnovsky	Manager, Strategic & Key Accounts
Donald Small	Manager, Gas Cost Knowledge Centre
Patricia Squires	Manager, Mass Market and New Construction Market Development
Liz Stokes-Bajcar	Manager, Human Resources Service Centre & Compensation
Michael Tremayne	Manager, Infrastructure & Marketing, NGV
Trevor Tuck	Manager, Engineering Special Projects
Annette Urquhart	Manager, Corporate Budgets & Planning
Marc Weil	Director, Information Technology
Henry Wong	Manager, Business Applications

In addition, the Company called the following witnesses:

P. Carpenter	Brattle Group

Intervenor Witnesses:

Lee Rose	Senior Vice-President, Home Services Canada, Direct Energy
Michael Shulist	The Shulist Group Inc.
Martin Luymes	Senior Director, HRAC Services and Relations, Heating, Refrigeration and Air-Conditioning Institute of Canada (HRAI)
Nancy McKeraghan	President, Canco Climate Care Inc.
Michael Latreille	Vice-President, Holmes Heating Inc.

Glen Leis	General Manager, OZZ Comfort Solutions
Roger Grochmal	President, Atlas Air ClimateCare
Paul Messenger	President, A1 Heating and Air Conditioning
Steve Kinsey	Private Investigator, Corporate Investigation Services
Laurence D. Booth	CIT Chair in Structured Finance, Rotman School of Business
David Kincaid	President and CEO, Level 5 Strategic Brand Advisors

APPENDIX B

ENBRIDGE GAS DISTRIBUTION INC.

2007 TEST YEAR

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0034

SETTLEMENT PROPOSAL

JULY 5, 2007

SETTLEMENT PROPOSAL

JANUARY 24, 2007

TABLE OF CONTENTS

ISSUE	**DESCRIPTION (& EVIDENTIARY REFERENCE)**
2.3	Is the forecast of degree days appropriate? (C2-4-1)
2.4	Are the average use-per-customer forecasts for rate class 1 and rate class 6 appropriate? (C1-3-1 and C2-3-1)
2.5	Is the proposed 2007 contract gas volume and revenue forecast appropriate? (C1-3-1)
2.6	Is the proposed 2007 General Service gas volume and revenue forecast appropriate? (C1-3-1)
3	**OPERATING COST (Exhibit D)**
3.1	Is the proposed 2007 gas cost forecast including the calculation of the PGVA Reference Price appropriate? (D1-4-1, D1-4-2)
3.2	Is the overall level of the 2007 Operation and Maintenance Budget appropriate? (D1-2-1)
3.3	Is the Company's proposed fuel switching program appropriate?
3.4	Is the Company's proposed Energy Link Program appropriate?
3.5	Is the budget for Human Resources related costs appropriate? (D1-4-1)
3.6	Do the revisions to the Regulatory Cost Allocation Methodology (RCAM) meet the Board's directives in the 2006 decision?
3.7	Is the proposed level of corporate cost allocation for 2007 appropriate?
3.8	Is Company's forecast level of Regulatory and OEB related costs for 2007 appropriate?
3.9	Is Enbridge's decision to change to a December 31 taxation year-end , in 2007, appropriate? (D1-5-1)
3.10	Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives? (D1-4-3)
3.11	Is the proposal to change depreciation rates for 2007, as proposed in the depreciation study, and the impact on 2007 customer rates,

<u>ISSUE</u> **<u>DESCRIPTION (& EVIDENTIARY REFERENCE)</u>**

appropriate? (D1-13-1, D2-2-1)

3.12 Is the proposal for the establishment of 2007 Deferral and Variance Accounts appropriate? (D1-7-1)

3.13 Is the proposal for the disposition of existing Deferral and Variance Accounts appropriate? (D1-7-2)

3.14 Are the amounts proposed to be included in rates for capital and property taxes appropriate?

3.15 Is the amount proposed to be included in rates for income taxes, including the methodology, appropriate?

4 COST OF CAPITAL (Exhibit E)

4.1 What is the Return on Equity (ROE) for EGDI for the 2007 test year as calculated pursuant to the ROE Guidelines?

4.2 Are Enbridge's proposed costs for its debt and preference share components of its capital structure appropriate? (E1-2-1)

4.3 Is the proposal to change the equity component of the deemed capital structure from 35% to 38% appropriate? (E2-2-1)

5 COST ALLOCATION (Exhibit G)

5.1 Is the Applicant's cost allocation appropriate and is it based in its 2006 Board approved methodology? (G2-T1-S1)

5.2 Is the proposal to recover Demand Side Management costs in delivery charges, as opposed to load balancing charges, appropriate? (from G2-3-1 to G2-3-4)

6 RATE DESIGN (Exhibit H)

6.1 Is the proposal to introduce delivery demand charges for Rates 100 and 145 reasonable? (H1-1-1)

6.2 Is the proposal to allocate revenue requirement between the customer classes and annually adjust the monthly customer charges and variable charges to recover the revenue deficiency reasonable? (H1-1-1)

ISSUE DESCRIPTION (& EVIDENTIARY REFERENCE)

6.3 Should the Board approve the contents of the Applicant's Rate Handbook? (H1-1-1, H2-6-1; A1-14-2)

6.4 Is the proposed treatment of bundled transportation charges and T-service credit appropriate in light of the Board's Decision in RP-2003-0203 and the settlement agreement? (H1-1-1)

7 CUSTOMER CARE SUPPORT, CUSTOMER CARE SYSTEM, AND OPEN BILL ACCESS

7.1 Has Enbridge complied with the direction, in the EB-2005-0001 Decision, to file in evidence the following Customer Care Support Cost information: all agreements between Enbridge and CWLP, ECSI or any other EI-related entity related to the provision of customer care or CIS; the Program Agreement between CWLP and Accenture, including any amendments or revisions; financial statements for ECSI and CWLP (historical, bridge and test year); the return analyses described in the decision? (D1-12-3)

7.2 What actions or decisions are required by the Board regarding items in the 2006 and 2007 capital budgets which might be duplicated in the upcoming application for a Regulatory Asset Account? (D1-10-1, p. 2/AppA)

7.3 Are the forecast costs of the new CIS system appropriate? (B1-5-1, p. 3)

7.4 What are the appropriate costs for CIS and Customer Care for 2007, including internal and transition costs? (D1-12-1, p. 2 and D3-2-1, p. 1)

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP 2005-0001? (D1-11-1 to 5)

8 OTHER ISSUES

8.1 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the NGEIR (EB-2005-0551) proceeding will be appropriately captured and reflected in this proceeding?

8.2 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the DSM

ISSUE DESCRIPTION (& EVIDENTIARY REFERENCE)

(EB-2006-0021) proceeding will be appropriately captured and reflected in this proceeding?

9 RATE IMPLEMENTATION

9.1 How should the Board deal with any revenue deficiency applicable from January 1, 2007 to the date that the Board's decision is implemented?

9.2 Should the Board set interim rates, effective January 1, 2007, to allow Enbridge to begin to recover its prospective revenue deficiency?

ATTACHMENTS

Appendix A- Deferral and Variance Accounts Balances

Appendix B- Approximations of rate impacts of the Settlement Proposal

PREAMBLE

This Settlement Proposal is filed with the Ontario Energy Board ("OEB" or "Board") in connection with the application of Enbridge Gas Distribution Inc. ("Enbridge Gas Distribution" or the "Company"), for an order or orders approving or fixing rates for the sale, distribution, transmission, and storage of gas for its 2007 fiscal year (the "Test Year").[1] A Settlement Conference was held between December 11, 2006 and January 5, 2007 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* (the "Rules") and the Board's *Settlement Conference Guidelines* ("Settlement Guidelines"). Ken Rosenberg acted as facilitator for the Settlement Conference. Settlement discussions between parties continued after that time. This Settlement Proposal arises from the Settlement Conference and subsequent discussions.

Enbridge Gas Distribution and the following intervenors (collectively, the "parties"), as well as Ontario Energy Board technical staff ("Board Staff"), participated in the Settlement Conference:

CONSUMERS COUNCIL OF CANADA (CCC)
DIRECT ENERGY MARKETING LIMITED (Direct Energy)
ENERGY PROBE RESEARCH FOUNDATION (Energy Probe)
GREEN ENERGY COALITION (GEC)
HVAC COALITION INC. (HVAC)
INDUSTRIAL GAS USERS ASSOCIATION (IGUA)
ONTARIO ASSOCIATION OF PHYSICAL PLANT ADMINISTRATORS (OAPPA)
ONTARIO ENERGY SAVINGS L.P. (OESLP)
POLLUTION PROBE
SCHOOL ENERGY COALITION (Schools)
SUPERIOR ENERGY MANAGEMENT (a division of Superior Plus Inc.) (Superior)
TRANSALTA COGENERATION L.P. AND TRANSALTA ENERGY CORP. (TransAlta)
TRANSCANADA PIPELINES LIMITED (TransCanada)
UNION ENERGY LIMITED PARTNERSHIP (Union Energy)
UNION GAS LIMITED (Union)
VULNERABLE ENERGY CONSUMERS COALITION (VECC)

The Settlement Proposal deals with all of the issues listed at Appendix "A" to the Board's Procedural Order #2, dated October 20, 2006 (the "Issues List"). The numbers ascribed to each of the issues correlate to the section numbers in the Settlement Proposal and each issue falls within one of the following three categories:

1. ***complete settlement –*** if the Settlement Proposal is accepted by the Board, the issue will not be addressed at the hearing because Enbridge

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[1] In this Settlement Proposal, the terms "2007 fiscal year", "fiscal 2007" and "Test Year" each refer to the twelve-month period commencing January 1, 2007 and ending December 31, 2007.

Gas Distribution and all other parties who take any position on the issue agree to the proposed settlement;

2. ***incomplete settlement –*** if the Settlement Proposal is accepted by the Board, portions of the issue will be addressed at the hearing because parties are only able to agree on some, but not all, aspects of the issue; and,

3. ***no settlement –*** the issue will be addressed at the hearing because the parties who participated in the negotiation of the issue are unable to reach a settlement on the issue.

More particularly, the Settlement Proposal depicts the 47 issues enumerated on the Issues List as follows:

Complete Settlement Parties will not address the issue at the hearing	**Incomplete Settlement** Parties will address one or more parts of the issue at the hearing	**No Settlement** Parties will address the issue at the hearing
25 issues completely settled Issues 1.1, 1.3 to 1.8, 2.1, 2.2, 3.1, 3.5, 3.7 to 3.9, 3.11, 3.14, 3.15, 4.1, 5.1, 5.2, 6.1, 6.4, 8.1, 8.2 and 9.2	7 issues partly settled Issues 1.2, 3.2, 3.12, 3.13, 6.2, 6.3 and 9.1	15 issues not settled Issues 2.3 to 2.6, 3.3, 3.4, 3.6, 3.10, 4.2, 4.3 and 7.1 to 7.5

Issue 3.2, which relates to the Company's O&M Budget for the Test Year is an incomplete settlement, however, it should be noted that GEC and Pollution Probe object to the settled portions of this issue. Issue 9.1, which relates to rate implementation, is an incomplete settlement, however, it should be noted that Schools objects to the settled portions of this issue.

The description of each issue assumes that all parties participated in the negotiation of the issue, unless specifically noted otherwise. Any parties that are identified as not having participated in the negotiations of the issue also take no position on any settlement or other wording pertaining to the issue. Board Staff participated in the Settlement Conference, and has advised the parties that it does not oppose the proposed settlement on any of the completely settled or partly settled issues. However, in accordance with the Rules and the Settlement Guidelines, Board Staff takes no position on any issue and, as a result, is not a party to the Settlement Proposal.

The Settlement Proposal describes the agreements reached on the completely settled and partially settled issues. The Settlement Proposal identifies the parties who agree and who disagree with each settlement, or alternatively who take no position on the issue. Finally, the Settlement Proposal provides a direct link between each settled issue and the supporting evidence in the record to date. In this regard, the parties who agree with the individual settlements are of the view that the evidence provided is sufficient to support the Settlement Proposal in relation to the settled issues and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings agreeing with the proposed resolution of the settled issues. In the event that the Board does not accept the proposed settlement of any issue, further evidence may be required on the issue for the Board to consider it fully.

Best efforts have been made to identify all of the evidence that relates to each settled issue. The supporting evidence for each settled issue is identified individually by reference to its exhibit number in an abbreviated format; for example, Exhibit A1, Tab 8, Schedule 1 is referred to as A1-8-1. A concise description of the content of each exhibit is also provided. In this regard, Enbridge Gas Distribution's response to an interrogatory is described by citing the name of the party and the number of the interrogatory (e.g., Board Staff Interrogatory #1). The identification and listing of the evidence that relates to each settled issue is provided to assist the Board. The identification and listing of the evidence that relates to each settled issue is not intended to limit any party who wishes to assert that other evidence is relevant to a particular settled issue.

The parties agree that all positions, information, documents, negotiations and discussion of any kind whatsoever which took place or were exchanged during the Settlement Conference are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Settlement Proposal.

According to the Settlement Guidelines (p. 3), the parties must consider whether a settlement proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. Enbridge Gas Distribution and the other parties who participated in the Settlement Conference consider that no settled issue requires an adjustment mechanism other than those expressly set forth herein.

Issues 1.1 to 1.8, 2.1, 2.2, 3.2, 3.5, 3.7 to 3.9, 3.11 to 3.15 and 9.1 have been settled by parties as a package (the “package”), subject to the objections of GEC, Pollution Probe and Schools, as noted earlier, and none of the parts of this package are severable. All parties agree that, for rate implementation purposes only, the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company’s April 1, 2007 QRAM is implemented. GEC’s and Pollution Probe’s agreement in this regard is subject to any later adjustments to the Company’s recovery of revenue deficiency that might be required as a result of

Issue 3.2. Schools' agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result of Issue 9.1. Subject to considering the objections of GEC, Pollution Probe and Schools during the hearing, if the Board does not, prior to the commencement of the hearing of the evidence in EB-2006-0034, accept the package in its entirety, then there is no Settlement Proposal (unless the parties agree that any portion of the package that the Board does accept may continue as part of a valid Settlement Proposal). None of the parties can withdraw from the Settlement Proposal except in accordance with Rule 32 of the Rules. Finally, unless stated otherwise, the settlement of any particular issue in this proceeding is without prejudice to the rights of parties to raise the same issue in any future proceeding.

OVERVIEW

In order to address certain issues that have continued to be the subject of debate and discussion over a number of years, and in order to satisfy Board directions from the Decision with Reasons in the EB-2005-0001 case (the 2006 rate case), during the past year the Company has entered into a number of consultative processes with stakeholders. These consultatives were convened in respect of EnVision (issues 1.5 and 1.6), Corporate Cost Allocation (issues 3.6 and 3.7), customer care and CIS (issues 3.2 and 7.1 to 7.4) and open bill access (issue 7.5). These consultative processes have contributed greatly to the ability of all parties to come to settlements on many of these issues, as set out below. Several of the consultative processes are ongoing and may lead to settlement of additional issues. If additional issues are partly or completely settled, parties propose to file a supplementary settlement agreement that would explain the settlements, and the incremental financial impacts of such settlements.

Parties have been able to agree upon the package, which includes settlement of many of the issues raised in this proceeding. While some issues remain outstanding and unresolved, the impact of this Settlement Proposal, if accepted, is that the scope and length of the proceeding will be substantially reduced.

The Company's Application sought recovery of a revenue deficiency of $167.8 million. This figure was updated to $158.7 million in Impact Statement No. 1, to account for, among other things, the ROE for the Test Year of 8.39%.

Parties have agreed upon the settlement package of issues that, if accepted, would reduce the revenue deficiency by $76.7 million. This would result in a remaining revenue /c
deficiency of $82.0 million. /c

The implementation of the settlement package of issues will result in a revenue deficiency of $29.9 million, based on the Company's filing which expresses the revenue deficiency /c
as being relative to the Board-approved rates for F2006, and all of the items that make up

and contribute to those rates including, for example, the agreed-upon level of degree days for F2006.

The issues that are not settled by the Settlement Proposal represent an additional revenue deficiency amount of $52.1 million, based on the Company's filing, which will /c require determination by the Board in the hearing. Based on positions that may be taken by parties in the hearing, the potential outcomes arising from the determination of these unsettled issues by the Board range from an incremental revenue sufficiency of approximately $5 million to an incremental revenue deficiency of $52.1 million. /c

Some intervenors assert that, if they are successful on outstanding issues (in particular issues related to Issue 2.2 regarding degree days), then there could be a revenue sufficiency in respect of those issues. Parties are able to agree, however, that for rate implementation purposes only, the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. This amount of $26.0 million will be subtracted from the total revenue deficiency resulting from the Board's final decision in this proceeding (which will include all impacts of this Settlement Proposal). The resulting revenue deficiency (or sufficiency) will be reflected and recovered in rates by the Company, subject to the outcome of Issue 9.1.

When implemented, the recovery of an additional $26.0 million will result in average increases, on an annual basis, of approximately 2% for Rate 1 customers, 1% for Rate 6 customers and between 0% and 2% increases for other rate classes. These average rate increases are relative to the July 1, 2006 QRAM rate and are calculated for a T-service customer, excluding commodity costs, and do not include impacts from the phase-in of cost allocation changes on October 1, 2006 and October 1, 2007. When these rate impacts are compared to the January 1, 2007 QRAM rate, the results are virtually identical as shown in Appendix B. The phase-in of cost allocation changes on October 1, 2007 will reduce the amounts recovered from Rate 1 and Rate 6 by approximately $5.01 million and $4.8 million respectively, and increase the amounts recovered from Rate 115, Rate 135 and Rate 170 by about $5.97 million, $0.6 million and $3.2 million respectively, as shown in Appendix B. The determination by the Board of the issues that are not settled will have additional rate impacts.

Attached as Appendix B is an approximation of the annual T-service rate increases that would result from the recovery of additional amounts of $26.0 million (the immediate additional amount to be recovered if the Settlement Proposal is accepted) and $82.0 /c million (the maximum recoverable revenue deficiency if the Settlement Proposal is accepted and the Board decides the unsettled issues by adopting the Company's position on these issues). These approximations do not take account of the clearance of deferral and variance accounts, the phase-in of cost allocation changes or any allocation changes that might result from the resolution of Issue 6.2. These average annual T-service rate impact estimates are not indicative of the percentage T-service rate increase that will occur on April 1, 2007, compared to T-service rates in force on March 31, 2007. T-service rate increases effective April 1, 2007 will include the rate increase associated with the nine month Rate Rider described in Issue 9.1. The Company believes, based on the analysis that it has undertaken, that these approximations of average annual T-service rate impacts, which are expressed relative to the July 1, 2006 QRAM rates and the January 1, 2007 QRAM rates, and are calculated for a T-service customer excluding commodity costs, are correct within +/- 0.5%.

1 RATE BASE (Exhibit B)

1.1 Are the amounts proposed for the 2007 Rate Base appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties have reached a global settlement of all 2007 Rate Base issues, except for issues related to the capital budget for the new CIS system. Issues related to the new CIS system are discussed below at Issues 7.2 to 7.4. The capital spending for the new CIS system will have no rate base impact in 2007. Parties agree that the Company will reduce the revenue deficiency associated with 2007 Rate Base issues by a total of $8 million, as compared to the Company's filed evidence. This will result in a 2007 capital budget of approximately $300 million, plus the cost of the Portlands Energy Centre Leave to Construct project, which is estimated at $18 million during the Test Year. The Portlands Energy Centre project, if approved in the leave to construct application, will not affect rates for the Test Year. Parties believe that the Board's consideration of the Portlands Energy Centre in the leave to construct application should be consistent with the principles set out under Issue 1.4 below.

Parties agree that the 2007 capital budget is an envelope amount, and the Company will have discretion to determine which items will be removed or changed from the Company's filed capital budget in order to reduce the overall level of that budget. Notwithstanding this discretion, the Company agrees that it will not proceed with the Automatic Meter Reading (AMR) project. Intervenors do not necessarily accept, and presently take no position on, the Company's decisions as to how it will allocate and spend the 2007 capital budget. Parties agree that, assuming the incentive regulation rate setting process allows for it, a normal review of the Company's capital spending in the Test Year may be undertaken as part of the rate setting process for 2008. The issue of capital spending on the EnergyLink program, included in Issue 3.4, is not settled, but the Board's decision on that issue will not affect the overall capital budget for the Test Year, only the Company's ability to allocate funds to EnergyLink within that budget. Parties accept the Company's opening rate base for 2007.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-1-1	Utility Rate Base
B1-1-2	Utility Rate Base Year to Year Summary
B1-2-1	Rate Base Capital Budget
B3-1-1	Ontario Utility Rate Base – Comparison of 2007 Test Year to 2006 Bridge Year
B3-1-2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2007 Test Year
B3-1-3	Working Capital Summary of Average of Monthly Averages 2007 Test Year
B3-2-1	Utility Capital Expenditures Comparison Budget 2007 and Estimated 2006
B3-2-2	2007 Capital Expenditures by Project (Projects Exceeding $500,000)
B3-2-3	Gross Customer Additions and Average Cost per Customer Addition Budget 2007 and Estimated 2006
B3-2-4	System Expansion Portfolio – 2007
F3-1-3	Utility Rate Base 2007 Test Year
I-1-1 to 3	Board Staff Interrogatories 1 to 3
I-9-4 and 7	IGUA Interrogatories 4 and 7
I-16-1 to 3	SEC Interrogatories 1 to 3
I-24-5 to 7	VECC Interrogatories 5 to 7
L-9-1	Evidence of IGUA
M1-1-1	Impact Statement #1

1.2 Are the amounts proposed for Capital Expenditures in 2007 appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

See Issue 1.1.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-2-1	Rate Base Capital Budget
B1-2-2	Details of Capital Expenditure and Justification for Major Capital Projects over $500,000
B1-3-1	Safety & Integrity Initiatives
B1-3-2	Leave to Construct Projects
B1-4-1	Information Technology Capital Budget
B1-5-1	CIS Project
B1-6-1	EnVision Project
B1-7-1	Automated Meter Reading (AMR)
I-1-4 to 6	Board Staff Interrogatories 4 to 6
I-2-1 to 4	CCC Interrogatories 1 to 4
I-9-2 and 5 to 6	IGUA Interrogatories 2 and 5 to 6

I-16-4 to 10	SEC Interrogatories 4 to 10
I-24-8 to 12	VECC Interrogatories 8 to 12

1.3 Is the budget amount proposed in 2007 for Safety & Integrity projects appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

See Issue 1.1. The Company will determine the 2007 capital expenditures budget for Safety and Integrity projects within the envelope set out under Issue 1.1.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-3-1	Safety & Integrity Initiatives
I-1-7	Board Staff Interrogatory 7
I-2-5 to 7	CCC Interrogatories 5 to 7
I-9-8	IGUA Interrogatory 8
I-16-11 to 12	SEC Interrogatories 11 to 12
I-24-13	VEC Interrogatory 13

1.4 How should the Board deal with the Leave to Construct ("LTC") projects included in the 2007 capital budget given that there will be separate Board Proceedings for the LTC projects?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties are of the view that the Board's decisions determining the appropriate total amount of capital spending by the Company in any test period are most suitably made in a rate application. In general, parties agree that the Board's decision with respect to overall capital spending does not imply specific approval of any individual leave to construct projects ("LTC Projects"), nor a decision as to the economic feasibility of any individual LTC Project. Similarly, parties agree that, generally, a decision with respect to the economic feasibility of an individual LTC

Project does not, in and of itself, imply that it is appropriate to include capital spending pertaining to that LTC Project in the capital budget for a test year used by the Board to establish rates.

In the context of the foregoing, the parties agree that the Board should deal with LTC Projects included in any test year capital budget as follows:

1. The total capital expenditures budget for a particular test year, to be considered and approved in a rate application, should include some evidence on individual LTC Projects planned for that year. However, the Board should not be asked to approve individual LTC Projects in a rate case. In a rate case, evidence with respect to individual LTC Projects need not be as extensive as the evidence required to support a LTC Application.

2. The economic feasibility of an individual project is considered in a leave to construct application. A LTC Application should not result in any adjustment to the Company's capital expenditures budget aside from exceptional circumstances, and in those cases the Board should consider and make the adjustment expressly.

3. A LTC Application can be heard by the Board prior to its consideration of the capital budget consequences of the LTC Project in a rates proceeding. In the event the Board approves a LTC Application, it will not be necessary to examine the justification for the LTC Project in a subsequent rate proceeding although the issue of the appropriate size of the overall capital budget would remain in issue in that hearing, and the leave to construct approval could inform that decision.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-3-2	Leave to Construct Projects
I-1-8 to 9	Board Staff Interrogatories 8 to 9
I-2-8	CCC Interrogatory 8
I-9-9	IGUA Interrogatory 9
I-16-13 to 14	SEC Interrogatories 13 to 14
I-19-4	TransAlta Interrogatory 4

1.5 Has the Company met the requirements of the Board's directive from the 2006 rate case to file an independent cost benchmark study for the EnVision project?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> Parties agree that the Company has met the requirements of the Board's directive from the EB-2005-0001 Decision with Reasons by filing an independent cost benchmark study for the EnVision project.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B2-2-1	Compass Report – Envision Cost Benchmark Analysis
B1-6-1	EnVision Project

1.6 What are the appropriate EnVision cost and benefits and how should they be reflected in 2007 rates?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> Parties agree that Compass carried out an appropriate cost benchmark study of the EnVision Project. Parties differ on how that benchmark should be applied in determining the costs and benefits associated with EnVision that should be reflected in rates. In order to resolve the EnVision issues in this proceeding, the Company has agreed to reduce the revenue requirement by $500,000 through a reduction in the 2007 Other O&M budget. This reduction is reflected and included in the $181.5 million total Other O&M budget agreed to below at Issue 3.2. The Company will continue to report annually to stakeholders on the achievement of EnVision benefits in the form and the manner set out in Tables 1 and 2 in Exhibit B1/T6/S1/pp 8-9. Parties agree that unless there is a change in the overall NPV of the EnVision project, there will be no need to revisit the EnVision project in future regulatory proceedings.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B2-2-1	Compass Report – Envision Cost Benchmark Analysis
B1-6-1	EnVision Project
1-2-9 to 17	CCC Interrogatories 9 to 17
1-16-15	SEC Interrogatory 15

1.7 Is the business case, including the total project amount of $133 million, proposed for the Automatic Meter Reading project ("AMR") justified?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

As part of the global settlement of 2007 rate base issues, the Company agrees not to proceed with the AMR project.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-7-1	Automated Meter Reading (AMR)
I-1-10 to 13	Board Staff Interrogatories 10 to 13
I-2-18 to 22	CCC Interrogatories 18 to 22
I-9-11	IGUA Interrogatory 11
I-16-16	SEC Interrogatory 16
I-24-14	VECC Interrogatory 14

1.8 Is the proposed recovery of AMR costs in 2007 rates appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> As part of the global settlement of 2007 rate base issues, the Company agrees not to proceed with the AMR project. As a result, this issue is no longer relevant.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-7-1	Automated Meter Reading (AMR)
1-24-15 to 16	VECC Interrogatories 15 to 16

2 OPERATING REVENUE (Exhibit C)

2.1 Is the proposed amount for 2007 Transactional Services revenue appropriate, and is the associated sharing mechanism in accordance with the 2006 decision?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> Parties agree that the Company will share net transactional services revenues with ratepayers on a 75:25 basis in favour of ratepayers for transportation-related transactional services and on a 90:10 basis in favour of ratepayers for storage-related transactional services. The Company agrees to credit $8 million in transactional services revenue to ratepayers, to be credited to the revenue requirement for the purpose of setting rates for the Test Year. This credit will not be allocated as between transportation and storage transactional services. The 2007 Transactional Services Deferral Account will include the total of the ratepayers' shares of the net transactional services revenue for transportation-related and for storage-related transactional services, less the $8 million credit and the O&M costs associated with storage-related transactional services (estimated at $.1 million in the Company's updated evidence at Ex. C1-4-2). For greater certainty, if the result of these calculations is that the year-end balance in the 2007

Transactional Services Deferral Account would be less than zero, the balance shall be deemed to be zero.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-4-1	Transactional Services Revenue
C1-4-2	Transactional Services – Supplementary Evidence
I-1-14 to 15	Board Staff Interrogatories 14 to 15
I-2-23	CCC Interrogatory 23
I-9-13	IGUA Interrogatory 13
1-16-17	SEC Interrogatory 17
I-24-17 to 18	VECC Interrogatory 17 to 18
M1-1-1	Impact Statement #1

2.2 Is the proposed total 2007 Other Revenue Forecast appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties agree to increase the forecast for Other Operating Revenue for the Test Year from $23.7 million to $28.9 million, inclusive of the $3.5 million incremental impact of the resolution of the Transactional Services issue (described above at Issue 2.1), an increase of $1.0 million from the forecast of Other Service Revenues in the Company's evidence and the imputation of revenue of $700,000 for the Natural Gas Vehicles (NGV) program for the Test Year (in order to reflect the revenue deficiency of the NGV program).

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-5-1	Other Service and Late Payment Penalty Revenues
C3-5-1	Rate of Return on Capital Employed in the Natural Gas Vehicles Program

I-1-16	Board Staff Interrogatory 16
I-2-24 to 25	CCC Interrogatories 24 and 25
I-16-18	SEC Interrogatory 18
I-24-19 to 22	VECC Interrogatories 19 to 22
M1-1-1	Impact Statement No. 1
M1-2-5	Change in Revenue Requirement

2.3 Is the forecast of degree days appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C2-4-1	Budget Degree Days
I-1-17	Board Staff Interrogatory 17
I-9-3 and 14	IGUA Interrogatories 3 and 14
1-5-1 to 12	Energy Probe Interrogatories 1 to 12
1-16-19 to 20	SEC Interrogatories 19 to 20
L-9-1	Evidence of IGUA

2.4 Are the average use-per-customer forecasts for rate class 1 and rate class 6 appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Volume Budget
C2-3-1	Average Rate Use 1
C2-3-2	Average Use Rate 6
I-1-18	Board Staff Interrogatory 18
I-2-26 to 28	CCC Interrogatories 26 to 28
I-16-21 to 23	SEC Interrogatories 21 to 23
I-24-22 to 25	VECC Interrogatories 22 to 25

2.5 Is the proposed 2007 contract gas volume and revenue forecast appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Volume Budget
I-1-19	Board Staff Interrogatory 19
I-1-12	IGUA Interrogatory 12

2.6 Is the proposed 2007 General Service gas volume and revenue forecast appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Volume Budget
C1-1-1	Operating Revenue Summary
C1-2-1	Revenue Forecast
C3-1-1	Utility Operating Revenue 2007 Test Year
C3-1-2	Comparison of Utility Operating Revenue Budget 2007 and Estimate 2006
I-1-20	Board Staff Interrogatory 20
1-24-23 to 25	VECC Interrogatories 23 to 25

3 OPERATING COST (Exhibit D)

3.1 Is the proposed 2007 gas cost forecast including the calculation of the PGVA Reference Price appropriate?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Parties accept the Company's forecast of the cost consequences of the gas supply portfolio for the Test Year.

The Company agrees with certain parties that, when the issues list for the Natural Gas Forum proceeding about QRAM methodology is discussed, the Company will support the inclusion of an issue regarding the detailed calculation of the PGVA Reference Price.

Participating Parties: All parties participated in the negotiation and settlement of this issue except GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-4-1	Cost of Gas, Transportation and Storage
D1-4-2	Status of Contracts
D3-3-1	Summary of Gas Cost to Operations
D3-3-2	Summary of Gas Storage and Transportation Costs Fiscal 2007
D3-3-3	Canadian Peak Day Supply Mix
D3-3-4	Monthly Pricing Information
D3-3-5	Gas Supply/Demand
I-1-21	Board Staff Interrogatory 21
I-2-29	CCC Interrogatory 29
I-5-16 to 17	Energy Probe Interrogatory 16 to 17
I-9-16	IGUA Interrogatory 16
I-18-6	Superior Interrogatory 6
I-21-1 to 9	TransCanada Interrogatories 1 to 9
I-24-26	VECC Interrogatory 26

3.2 Is the overall level of the 2007 Operation and Maintenance Budget appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

> The Company's overall Operations and Maintenance (O&M) budget, as filed in Impact Statement No. 1, for the Test Year totalled $365.8 million and can be divided into a number of categories: (i) customer care expenses (including CIS, internal costs and provision for uncollectibles) – filed as $120.1 million; (ii) corporate cost allocations – filed as $22.9 million; (iii) demand side management (DSM) programs – filed as $22.0 million; and (iv) Other O&M – filed as $200.8 million. The Company has also included transition costs of $10 million related to customer care as a separate line item in its filing.
>
> Issues related the Company's customer care O&M budget (including the transition costs) are discussed below at Issues 7.1 to 7.4. Parties, except for GEC and Pollution Probe, agree on the balance of the Company's O&M budget for the Test Year.
>
> Parties acknowledge that the Company's O&M DSM budget for the Test Year shall be $22.0 million, as set out in the Board's Decision with Reasons in EB-2006-0021 (the DSM generic hearing).
>
> Parties agree that the Company's O&M budget for corporate cost allocations for the Test Year shall be $18.1 million. Parties agree to the overall level of this budget, but there is no specific agreement as to the amounts of each of the

individual allocations. The issues about the corporate cost allocation methodology set out in Issue 3.6 remain unsettled.

Parties, except for GEC and Pollution Probe, agree that the Company's Other O&M budget for the Test Year, filed as $200.8 million, shall be reduced by $19.3 million to $181.5 million. Subject to the comments below, parties agree that the amount of the Other O&M budget is an envelope amount and the Company will have discretion to determine which items will be removed or changed from the Company's Other O&M budget as filed in order to reduce the overall level of that budget. Intervenors do not necessarily accept, and presently take no position on, the Company's decisions as to how it will allocate and spend the 2007 Other O&M budget.

Notwithstanding the agreement on the overall level of the Company's Other O&M budget for the Test Year, parties agree that certain components of the Company's Opportunity Development planned activities for the Test Year, specifically marketing activities, fuel switching and EnergyLink, will be examined before the Board. Parties, except for GEC and Pollution Probe, agree that the examination of those sub-issues before the Board will not impact on the $181.5 million agreed-upon level of the Other O&M budget for the Test Year. Subject to the exception set out below, parties other than GEC and Pollution Probe agree that they will not take any position in this proceeding on how the Company ought to allocate the agreed-upon $181.5 million Other O&M budget. Notwithstanding the foregoing, in the event that the Board determines that the Company may not proceed with EnergyLink, it is understood that Schools and/or HVAC may advance arguments about how the Company ought to spend the O&M amounts totaling $1.3 million (Ex. I-26-4) that were otherwise budgeted for EnergyLink. Notwithstanding the foregoing, it is also understood that VECC may advance arguments that the Company ought to allocate funds as budgeted of $925,000 to low income fuel switching (Ex. 1-24-29). Additionally, the Company agrees that from and after the date of the Board's decision in this proceeding, it will not allocate any portion of the agreed-upon $181.5 million Other O&M budget to any specific marketing, fuel switching or EnergyLink activities that the Board specifically states the Company should not be undertaking.

GEC and Pollution Probe do not agree to the $181.5 million Other O&M budget. GEC and Pollution Probe wish to examine the Company's Opportunity Development (OD) O&M budget separately and do not agree to the overall level of $181.5 million for the Other O&M budget. No other parties, including the Company, will support or argue for any change (increase or decrease) to the agreed-upon Other O&M budget of $181.5 million.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, OAPPA, OESLP, Superior, TransCanada, TransAlta, Union Gas.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue except Pollution Probe and GEC.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Operating Cost Summary
D1-2-1	Operating, Maintenance and Other Costs
D2-1-1	Corporate Cost Allocation
D3-1-1	Operating Cost 2007 Test Year
D3-2-1	Operating Cost Comparison of Utility Cost and Expenses Budget 2007 and Estimate 2006
D3-2-2	Operating and Maintenance Expense by Department
D3-2-3	Operating and Maintenance Expense by Cost Type
I-1-22 to 24	Board Staff Interrogatories 22 to 24
I-2-30 to 35	CCC Interrogatories 30 to 35
I-9-2, 4 and 15	IGUA Interrogatories 2, 4 and 15
I-15-1 to 4	Pollution Probe Interrogatories 1 to 4
I-16-24 to 29	SEC Interrogatories 24 to 29
I-24-27 to 28	VECC Interrogatories 27 to 28
L-9-1	Evidence of IGUA
M1-1-1	Impact Statement #1

3.3 Is the Company's proposed fuel switching program appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-8-1	Opportunity Development – Market Development
I-1-25	Board Staff Interrogatory 25
I-2-36 to 39	CCC Interrogatories 36 to 39
I-7-1	GEC Interrogatory 1
I-22-6	Union Energy Interrogatory 6
I-24-29	VECC Interrogatory 29
I-26-1 to 3	HVAC Interrogatory 1 to 3

3.4 Is the Company's proposed Energy Link program appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Operating Cost Summary
I-22-6	Union Energy Interrogatory 6
I-24-30	VECC Interrogatory 30
I-26-4 to 10	HVAC Interrogatories 4 to 10
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-36 to 46	Enbridge Gas Distribution Interrogatories of Union Energy 36 to 46
I-30-1 to 21	Enbridge Gas Distribution Interrogatories of HVAC 1 to 21

3.5 Is the budget for Human Resources related costs appropriate?

(Complete Settlement)

There is an agreement to settle this issue as part of the package, as follows:

> Parties agree that any Human Resources related costs determined by the Company to be appropriate in the Test Year will be included as part of the agreed-upon $181.5 million Other O&M budget.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-2-1	Operating Costs and Maintenance and Other Costs
D1-2-2	Employee Expenses and Workforce Demographics
D3-2-4	Salaries and Wages and FTE Forecast 2007 Test Year
I-1-26	Board Staff Interrogatory 26
I-2-40 to 43	CCC Interrogatories 40 to 43
I-16-30 to 37	SEC Interrogatories 30 to 37
I-24-31 to 33	VECC Interrogatories 31 to 33

3.6 Do the revisions to the Regulatory Cost Allocation Methodology (RCAM) meet the Board's directives in the 2006 decision?

(No Settlement)

There is no agreement to settle this issue.

The issue of whether the revisions to RCAM meet the Board's directives from the 2006 decision has been a subject of the corporate cost allocation consultative. At this time, the final report from the consultant retained on behalf of the consultative has not been filed. As a result, no settlement can be reached on this issue at this time.

Evidence: The evidence in relation to this issue includes the following:

D2-1-1	Corporate Cost Allocation
G1-1-1	Corporate Cost Allocation Methodology
I-16-38 to 39	SEC Interrogatories 38 to 39

3.7 Is the proposed level of corporate cost allocation for 2007 appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties agree that the Company's O&M budget for corporate cost allocations for the Test Year shall be $18.1 million. Parties agree to the overall level of this budget, but there is no specific agreement as to the amounts of each of the individual allocations.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-2-1	Operating Maintenance and Other Costs
D2-1-1	Corporate Cost Allocation
I-1-27 to 28	Board Staff Interrogatories 27 to 28
I-9-1	IGUA Interrogatory 1
I-24-34 to 37	VECC Interrogatories 34 to 37

3.8 Is Company's forecast level of Regulatory and OEB related costs for 2007 appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> Parties agree that the Company's Regulatory and OEB related costs will be included as part of the agreed-upon Other O&M budget and that variances from the budget for 2007 rate proceeding related expenses will be recorded in the 2007 Ontario Hearings Costs Variance Account for consideration and disposition in a future proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-2-1	Operating Maintenance and Other Costs
D1-9-1	Regulatory Costs
I-1-29 to 30	Board Staff Interrogatories 29 to 30
I-2-44	CCC Interrogatory 44
I-16-40	SEC Interrogatory 40

3.9 Is Enbridge's decision to change to a December 31 taxation year-end , in 2007, appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> Intervenors have relied on the Company's evidence that the change of taxation year-end for the Enbridge Gas Distribution Inc. corporate entity has no impact on the Company's 2007 cost of service. In conjunction with the agreement with respect to Issue 3.15, intervenors accept the Company's evidence in this regard.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-5-1	Taxation Year-End Change

I-1-31 to 34	Board Staff Interrogatories 31 to 34
I-16-41	SEC Interrogatory 41

3.10 Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-4-3	Gas Supply Risk Management
I-1-35 to 36	Board Staff Interrogatories 35 to 36
I-2-45	CCC Interrogatory 45
I-5-18 to 27	Energy Probe Interrogatories 18 to 27
I-18-7	Superior Interrogatory 7
I-24-38 to 39	VECC Interrogatories 38 to 39
L-5-1	Evidence of Energy Probe
I-36-1 to 6	Enbridge Gas Distribution Interrogatories of Energy Probe 1 to 6

3.11 Is the proposal to change depreciation rates for 2007, as proposed in the depreciation study, and the impact on 2007 customer rates, appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> The Company agrees not to proceed with its request to change depreciation rates for 2007. Intervenors agree not to challenge the Company's existing depreciation rates for 2007. Notwithstanding this agreement, parties may examine the existing level of the Company's depreciation rates in the context of discussing and examining other outstanding issues in this proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-13-1	Depreciation Rate Change
D2-2-1	Depreciation Study

I-1-37 to 46	Board Staff Interrogatories 37 to 46
I-5-13 to 14	Energy Probe Interrogatories 13 to 14
I-9-18	IGUA Interrogatory 18
I-16-42 to 41	SEC Interrogatories 42 to 43
I-24-39.1 to 39.3	VECC Interrogatories 39.1 to 39.3
L-9-1	Evidence of IGUA

3.12 Is the proposal for the establishment of 2007 Deferral and Variance Accounts appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

> The Company's proposal to establish the following deferral and variance accounts for the Test Year is accepted by the parties for the reasons set out in the Company's evidence:
>
> 2007 Purchased Gas Variance Account ("2007 PGVA")
> 2007 Transactional Services Deferral Account ("2007 TSDA")
> 2007 Unaccounted for Gas Variance Account ("2007 UAFVA")
> 2007 Union Gas Deferral Account ("2007 UGDA")
> 2007 Class Action Suit Deferral Account ("2007 CASDA")
> 2007 Debt Redemption Deferral Account ("2007 DRDA")
> 2007 Deferred Rebate Account ("2007 DRA")
> 2007 Gas Distribution Access Rule Costs Deferral Account ("2007 GDACRDA")
> 2007 Manufactured Gas Plant Deferral Account ("2007 MGPDA")
> 2007 Ontario Hearing Costs Variance Account ("2007 OHCVA")
> 2007 Electric Program Earnings Sharing Deferral Account ("2007 EPESDA")
> 2007 Unbundled Rate Implementation Cost Deferral Account ("2007 URICDA")
> 2007 Unbundled Rates Customer Migration Deferral Account ("2007 URCMDA")
> 2007 Demand-Side Management Variance Account ("2007 DSMVA")
> 2007 Lost Revenue Adjustment Mechanism ("2007 LRAM")
> 2007 Shared Savings Mechanism Variance Account ("2007 SSMVA")
> 2007 Income Tax Rate Change Variance Account ("2007 ITRCVA")
>
> There is no agreement to the establishment of the following deferral and variance accounts, as those accounts are being dealt with as part of the customer care/CIS consultative process and through Issues 7.2 to 7.4:
>
> 2007 Customer Information System Procurement Deferral Account ("2007 CISPDA")
> 2007 Customer Care Procurement Deferral Account ("2007 CCPDA")
> 2007 Customer Care Supplier Transition Variance Account ("2007 CCSTVA")
>
> There is no agreement to the establishment of the following deferral account, as it is being dealt with as part of the open bill consultative process and through Issue 7.5:
>
> 2007 Open Bill Access Sharing Deferral Account ("2007 OBASDA")

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-7-1	Deferral and Variance Accounts
D1-7-3	Deferral and Variance Account Balances
I-1-47	Board Staff Interrogatory 47
I-2-46 to 48	CCC Interrogatories 46 to 48
I-7-2	GEC Interrogatory 2

3.13 Is the proposal for the disposition of existing Deferral and Variance Accounts appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

Enbridge Gas Distribution filed a summary of the actual deferral account and variance account balances for F2006 (D1-7-3); the summary is reproduced in Appendix A. The result of clearing certain of these accounts is that Enbridge Gas Distribution will credit customers $23.258.7 million in principal plus interest, based upon the December 31, 2006 balances, for F2006.

The balances recorded in the following deferral and variance accounts established for F2006, and the proposed clearance of such balances at the same time as the final rate order in this proceeding is implemented, are accepted by the other parties for the reasons given in the supporting evidence:

<u>Non Commodity Related Accounts</u>

2004 Demand-Side Management Variance Account ("2004 DSMVA")
2004 Lost Revenue Adjustment Mechanism ("2004 LRAM")
2004 Shared Savings Mechanism Variance Account ("2004 SSMVA")
2006 Deferred Rebate Account (“2006 DRA”)
2006 Debt Redemption Deferral Account (“2006 DRDA”)
2006 Ontario Hearing Costs Variance Account (“2006 OHCVA”)

<u>Commodity Related Accounts</u>

2006 Unaccounted for Gas Variance Account (“2006 UAFVA”)
2006 Transactional Services Deferral Account (“2006 TSDA”)

2006 Union Gas Deferral Account ("2006 UGDA")

Enbridge Gas Distribution does not seek to clear, in the Test Year, the balances recorded in the following deferral and variance accounts. Parties agree that the following previously-approved deferral and variance accounts are continued and the clearance of these accounts will be addressed by the Board in the future.

<u>Non Commodity Related Accounts</u>

2006 Demand-Side Management Variance Account ("2006 DSMVA")
2005 Demand-Side Management Variance Account ("2005 DSMVA")
2006 Lost Revenue Adjustment Mechanism ("2006 LRAM")
2005 Lost Revenue Adjustment Mechanism ("2005 LRAM")
2006 Shared Savings Mechanism Variance Account ("2006 SSMVA")
2005 Shared Savings Mechanism Variance Account ("2005 SSMVA")
2006 Manufactured Gas Plant Deferral Account ("2006 MGPDA")
2006 Corporate Cost Allocation Deferral Account ("2006 CCAMDA")
2006 Class Action Suit Deferral Account ("2006 CASDA")

<u>Commodity Related Account</u>

2006 Purchased Gas Variance Account ("2006 PGVA")

While Enbridge Gas Distribution seeks to clear the balances recorded in the following deferral and variance accounts in the Test Year, there is no agreement as to whether this is appropriate and these accounts will be addressed at the hearing:

2006 Gas Distribution Access Rule Costs Deferral Account ("2006 GDARCDA")
2005 Gas Distribution Access Rule Costs Deferral Account ("2005 GDARCDA")
2006 Alliance Vector Appeal Costs Deferral Account ("2006 AVACDA")
2006 Gas Supply Risk Management Program Deferral Account ("2006 GSRMPDA")
2006 Electric Program Earnings Sharing Deferral Account ("2006 EPESDA")
2006 Unbundled Rate Implementation Cost Deferral Account ("2006 URICDA")

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-7-1	Deferral and Variance Accounts
D1-7-2	Proposed Clearing of the 2006 Deferral Accounts
D1-7-3	Deferral and Variance Account Balances
A1-13-1	Status of Board Directives from Previous Board Decisions and/or Orders
A3-3-1	Financial Statements – Enbridge Gas Distribution Historical 2005 Year

A3-4-1	Annual Report (Actual) and Management Discussion and Analysis (MD&A)
I-2-49	CCC Interrogatory 49
I-16-44 to 45	SEC Interrogatories 44 to 45
I-24-40	VECC Interrogatory 40

3.14 Are the amounts proposed to be included in rates for capital and property taxes appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

The Company agrees to a $1.3 million reduction in its forecast of municipal property and other taxes for the Test Year.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D3-1-1	Operating Cost 2007 Test Year
I-9-3	IGUA Interrogatory 3
I-2-50	CCC Interrogatory 50

3.15 Is the amount proposed to be included in rates for income taxes, including the methodology, appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties accept the Company's methodology for income taxes, and the amount to be included in rates for income taxes, for the purpose of setting rates for the Test Year, without prejudice to the ability of any party to raise issues with respect to the methodology and its resulting calculations, including but not limited to which inclusions and deductions are appropriate, in future rate proceedings. The Company agrees to create a 2007 Income Tax Rate Change Variance Account to capture the impact of any corporate income tax rate changes against Fiscal 2007 Board Approved taxable income (versus the Company's forecast of corporate income tax rates) that occur in 2007 as a result of Provincial and Federal government budgets that are passed in the Test Year.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

A3-2-1	Financial Statements – Utility Proforma Statements for Bridge and Test Year
A3-3-1	Financial Statements – Enbridge Gas Distribution Historical 2005 Year
A3-4-1	Annual Report (Actual) and Management Discussion and Analysis (MD&A)
A3-5-3	Annual/Audited Financial Reports (Historical) Enbridge Inc. – 2005 Year
D3-1-1	Operating Cost 2007 Test Year
I-16-46 to 47	SEC Interrogatories 46 to 47

4 COST OF CAPITAL (Exhibit E)

4.1 What is the Return on Equity (ROE) for EGDI for the 2007 test year as calculated pursuant to the ROE Guidelines?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Parties agree that the ROE for the Company for the 2007 test year is 8.39%, as calculated pursuant to the ROE guidelines.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Cost of Capital Summary
E1-2-1	Cost of Capital
E2-1-1	Utility Business and Financial Risks
E2-1-2	Enbridge Gas Distribution Utility Business Risks – Environment
E2-1-3	Utility Equity Thickness Financial Risk Update
E2-2-1	Calculation of ROE

E3-1-1	Cost of Capital 2007 Test Year
E3-1-2	Summary Statement of Principal and Carrying Costs of Term Debt 2007 Test Year
E3-1-3	Unamortized Debt Discount and Expense Average of Monthly Averages 2007 Test Year
E3-1-4	Preference Shares Summary Statement of Principal and Carrying Cost 2007 Test Year
E3-1-5	Unamortized Preference Share Issue Expense Average of Monthly Averages 2007 Test Year
E3-1-6	Fiscal 2007 Calculation of Short-term Unfunded Debt
I-5-15	Energy Probe Interrogatory 15
I-24-41 to 43	VECC Interrogatories 41 to 43
M1-1-1	Impact Statement #1

4.2 Are Enbridge's proposed costs for its debt and preference share components of its capital structure appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Cost of Capital Summary
E1-2-1	Cost of Capital
I-1-48	Board Staff Interrogatory 48
I-16-48 to 50	SEC Interrogatories 48 to 50

4.3 Is the proposal to change the equity component of the deemed capital structure from 35% to 38% appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Cost of Capital Summary
E1-2-1	Cost of Capital
E2-1-1	Utility Business and Financial Risks
E2-1-2	Utility Equity Thickness Financial Risk Update
E2-1-2	Enbridge Gas Distribution Utility Business Risks – Environment
E2-2-1	Calculation of ROE
E3-1-1	Cost of Capital 2007 Test Year
I-2-51	CCC Interrogatory 51
I-9-19	IGUA Interrogatory 19
I-16-51 to 54	SEC Interrogatories 51 to 54
I-24-44 to 57	VECC Interrogatories 44 to 57
I-24-77 to 83	VECC Supplementary Interrogatories 77 to 83
L-9	Evidence of IGUA
L-27-1	Evidence of VECC, CCC and IGUA
L-27-2	Supplementary Evidence of VECC, CCC and IGUA
I-28-1 to 17	Enbridge Gas Distribution Interrogatories of VECC, CCC and IGUA 1 to 17

5 COST ALLOCATION (Exhibit G)

5.1 Is the Applicant's cost allocation appropriate and is it based in its 2006 Board approved methodology?

(Complete Settlement)

There is an agreement to settle this issue as follows:

> Subject to the comments below in respect of Issues 6.2, 6.4 and 8.1, and subject to a compliance review of the cost allocation that will be embedded in any rate orders arising from this proceeding, parties accept the Company's evidence in this proceeding about its cost allocation for the Test Year and agree that it is appropriate and consistent with the 2006 Board-approved methodology.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransAlta, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	Cost Allocation Methodology
G2-1-1	Fully Allocated Cost Study
I-1-52	Board Staff Interrogatory 52
I-9-20	IGUA Interrogatory 20
I-24-59	VECC Interrogatory 69

5.2 Is the proposal to recover Demand Side Management costs in delivery charges, as opposed to load balancing charges, appropriate?

(Complete Settlement)

There is an agreement to settle this issue as follows:

> Parties accept the Company's proposal, as set out in the evidence, to recover Demand Side Management costs in delivery charges, rather than in load balancing charges.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

G2-3-1	Functionalization of Utility Rate Base
G2-3-2	Functionalization of Utility Working Capital
G2-3-3	Functionalization of Utility Net Investments
G2-3-4	Functionalization of Utility O&M
I-1-53	Board Staff Interrogatory 53

6 RATE DESIGN (Exhibit H)

6.1 Is the proposal to introduce delivery demand charges for Rates 100 and 145 reasonable?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Parties accept the Company's proposal, as set out in the evidence, to introduce delivery demand charges for Rates 100 and 145.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue except TransAlta and VECC, which take no position.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
H2-1-1	Revenue Comparison – Current Revenue vs. Proposed Revenue
H2-2-1	Proposed Revenue Recovery by Rate Class
H2-3-1	Summary of Proposed Rate Change by Rate Class
H2-4-1	Calculation of Gas Supply Charges by Rate Class
H2-5-1	Detailed Revenue Calculations by Rate Class
H2-6-1	Rate Handbook
H2-7-1	Annual Bill Comparison
H3-1-1	Revenue Comparison – Current vs Proposed by Rate Class Proposed Methodology
H3-1-2	Proposed Unit Rates by Rate Class
H3-2-1	Proposed Revenue Recovery by Rate Class

H3-3-1	Summary of Proposed Rate Change
H3-4-1	Calculation of Gas Supply Charges by Rate Class
H3-5-1	Detailed Revenue Calculations by Rate Class
H3-6-1	Rate Handbook
H3-7-1	Annual Bill Comparison
I-1-54	Board Staff Interrogatory 54
I-12-1	OAPPA Interrogatory 1

6.2 Is the proposal to allocate revenue requirement between the customer classes and annually adjust the monthly customer charges and variable charges to recover the revenue deficiency reasonable?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue as follows:

> Parties accept the Company's proposal, as set out in the evidence, to annually adjust the monthly customer charges and variable charges to recover the revenue deficiency.
>
> There is no agreement about the Company's proposal to allocate revenue requirement between customer classes. Some parties are concerned that the allocation of the 2007 revenue deficiency as proposed in the Company's evidence results in the collection of revenues greater than allocated costs from Rate 1 and Rate 6 customers based on the Company's filed Revenue to Cost ratios of 1.02 and 1.01 for these rate classes. These parties wish to explore the proposed 2007 revenue requirement allocation in light of the evidence and interrogatory responses on this issue. Other parties support the Company's revenue deficiency allocation and will oppose changes to it.

Participating Parties: All parties participated in the negotiation and settlement of aspects of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada**.**

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
H2-1-1	Revenue Comparison – Current Revenue vs. Proposed Revenue
H2-2-1	Proposed Revenue Recovery by Rate Class
H2-3-1	Summary of Proposed Rate Change by Rate Class
H2-4-1	Calculation of Gas Supply Charges by Rate Class
H2-5-1	Detailed Revenue Calculations by Rate Class
H2-6-1	Rate Handbook

H2-7-1	Annual Bill Comparison
H3-1-1	Revenue Comparison – Current vs Proposed by Rate Class Proposed Methodology
H3-1-2	Proposed Unit Rates by Rate Class
H3-2-1	Proposed Revenue Recovery by Rate Class
H3-3-1	Summary of Proposed Rate Change
H3-4-1	Calculation of Gas Supply Charges by Rate Class
H3-5-1	Detailed Revenue Calculations by Rate Class
H3-6-1	Rate Handbook
H3-7-1	Annual Bill Comparison
I-1-55	Board Staff Interrogatory 55
I-9-23	IGUA Interrogatory 23
I-12-2	OAPPA Interrogatory 2
I-24-70	VECC Interrogatory 70

6.3 Should the Board approve the contents of the Applicant's Rate Handbook?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue as follows:

> Parties agree that it is appropriate for the Board to continue to approve the Company's Rate Handbook, as part of the Rate Order resulting from Rate Case proceedings.
>
> There is no agreement on the Company's proposed Invoice Vendor Adjustment (IVA) charge.
>
> Subject to the issue about the IVA, parties agree that the Rate Handbook as filed should be approved by the Board.

Participating Parties: All parties participated in the negotiation and settlement of this issue except GEC, HVAC, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

A1-14-1	Policies and Regulations of the Company with Respect to Gas Services and Schedule of Service Charges
A1-14-2	Changes to the Schedule of Service Charges
D1-10-2	Gas Distribution Access Rule
H1-1-1	Rate Design
H2-6-1	Rate Handbook
I-19-1	TransAlta Interrogatory 1
I-1-56	Board Staff Interrogatory 56
I-12-3	OAPPA Interrogatory 3
I-24-71 to 73	VECC Interrogatories 71 to 73

6.4 Is the proposed treatment of bundled transportation charges and T-service credit appropriate in light of the Board's Decision in RP-2003-0203 and the settlement agreement?

(Complete Settlement)

There is agreement to settle this issue as follows:

> Parties accept the Company's proposed treatment of bundled transportation charges and T-service credits. The final rate increases associated with the implementation of the settlement proposal of the changes in the allocation of upstream transportation charges in EB-2005-0001 will be implemented on October 1st, 2007. Effective October 1, 2007, the upstream transportation charges for all rate classes will recover the appropriate level of upstream transportation costs for all rate classes, so that there will be no over-contribution from Rates 1 and 6 with respect to upstream transportation costs.
>
> The Company will continue to charge and rebate the T-service credit for Ontario T-Service customers. The existing T-Service credit, equal to TransCanada's 100% load factor toll, will continue to be in effect until December 31, 2007. Effective January 1, 2008, the T-Service credit will be based on the weighted average cost of transportation, equal to the unit rate based on total utility transportation costs over total delivery volumes. The Company will treat T-Service credits for Ontario T-Service customers in this manner, as an "off-set", from January 1, 2008 until such time as the Company has a new billing system that permits a different approach. This approach satisfies the Board's directive regarding the Company's obligation to phase-out the T-service credit for Ontario T-Service customers as outlined in the RP-2003-0203 Settlement Proposal.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
I-1-57	Board Staff Interrogatory 57
I-12-4	OAPPA Interrogatory 4

7 CUSTOMER CARE SUPPORT, CUSTOMER CARE SYSTEM, AND OPEN BILL ACCESS

7.1 Has Enbridge complied with the direction, in the EB-2005-0001 Decision, to file in evidence the following Customer Care Support Cost information: all agreements between Enbridge and CWLP, ECSI or any other EI-related entity related to the provision of customer care or CIS; the Program Agreement between CWLP and Accenture, including any amendments or revisions; financial statements for ECSI and CWLP (historical, bridge and test year); the return analyses described in the decision?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

D1-12-1	Customer Care - Overview
D1-12-2	Customer Care and Transition Costs
D1-12-3	Customer Care – Benchmarking
I-1-58	Board Staff Interrogatory 58
I-9-17	IGUA Interrogatory 17
I-16-55 to 58	SEC Interrogatories 55 to 58

7.2 What actions or decisions are required by the Board regarding items in the 2006 and 2007 capital budgets which might be duplicated in the upcoming application for a Regulatory Asset Account?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

D1-10-1	GDAR
I-1-59	Board Staff Interrogatory 59

7.3 Are the forecast costs of the new CIS system appropriate?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

B1-5-1	CIS Project
I-1-60 to 63	Board Staff Interrogatories 60 to 63
I-9-10	IGUA Interrogatory 10
I-26-11	HVAC Interrogatory 11

7.4 What are the appropriate costs for CIS and Customer Care for 2007, including internal and transition costs?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

B1-5-1	CIS Project
D1-12-1	Customer Care – Overview
D1-12-2	Customer Care and Transition Costs
D1-12-3	Customer Care – Benchmarking
D3-2-1	Operating Cost Comparison of Utility Cost and Expenses Budget 2007 and Estimate 2006
I-1-64 to 73	Board Staff Interrogatories 64 to 73
I-16-59	SEC Interrogatory 59

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?

(No Settlement)

There is no agreement to settle this issue, although the consultative is ongoing.

Evidence: The evidence in relation to this issue includes the following:

D1-11-1	Open Bill Access
D1-11-2	Statement of Principles, Objectives and Operating Arrangements for the Consultation Process for Enbridge Gas Distribution's Open Bill Access Proposal
D1-11-3	Open Bill Access Consultative Process
D1-11-4	Meeting Minutes
D1-11-5	Third Party Access Report
D1-11-6	Open Bill Access Update
D1-11-7	Summary Notes from Consultative Meeting on Wednesday July 26, 2006
D1-11-8	Open Bull Access Update – July 26th, 2006
D1-11-9	Summary Notes from Consultative Meeting on Tuesday November 14th, 2006
D1-11-10	Presentation – Consultative Meeting on Tuesday November 14th, 2006
D1-11-11	Open Bill Access Standard Bill Service Consultative November 14th, 2006
D1-11-12	Bill Insert Agreement
D1-11-13	Open Bill Standard Bill Service Description – Meeting November 14th, 2006 – Additional Request for Information
D1-11-14	Bill Inserts
D1-11-15	Bill Insert Agreement Draft
D1-11-16	Initial Draft for Discussion Binding request for Bids – Third Party Bill Inserts for 2007
D1-11-17	Presentation – Consultative Meeting on November 23rd, 2006
D1-11-18	Open Bill Access – Summary Notes from Consultative Meeting on November 23rd, 2006
D1-11-19	Presentation – November 30th, 2006
D1-11-20	Criteria for Bill Inserts
D1-11-21	Open Bill Access – Summary Notes from Conference Call between EGD, Intervenors, and Consultants on Friday, December 1st, 2006
D1-11-22	Shared Bill Benefit Calculation
D1-11-23	Presentation – December 5th, 2006 Corrected Forecast
D1-11-24	Bill Inserts
D1-11-25	Bill Inserts
D1-11-26	Bill Inserts
D1-11-27	Request for Binding Bids – 2007 Third Party Bill Insert Service
D1-11-28	Binding Service Request and Bid Form – 2007 Third Party Bill Insert Service
I-1-74 to 77	Board Staff Interrogatories 74 to 77
I-2-52	CCC Interrogatory 52
I-4-1 to 12	Direct Energy Interrogatories 1 to 12
I-16-60 to 61	SEC Interrogatories 60 to 61
I-18-1 to 5	Superior Interrogatories 1 to 5
I-22-1 to 5	Union Energy Interrogatories 1 to 5
I-24-74 to 75	VECC Interrogatories 74 to 75
I-26-12 to 20	HVAC Interrogatories 12 to 20
L-4-1	Evidence of Direct Energy
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-1 to 35	Enbridge Gas Distribution Interrogatories of Union Energy 1 to 35
I-29-1 to 5	Enbridge Gas Distribution Interrogatories of Direct Energy 1 to 5
I-30-22 to 24	Enbridge Gas Distribution Interrogatories of HVAC 22 to 24
I-32-1 to 5	HVAC Interrogatories of Direct Energy 1 to 5

I-33-1 to 12	Superior Energy Management Interrogatories 1 to 12
I-34-1 to 21	Union Energy Interrogatories of Direct Energy 1 to 21
I-35-1 to 11	Direct Energy Interrogatories of Union Energy 1 to 11
I-36-1 to 16	Direct Energy Interrogatories of HVAC 1 to 16
	Transcript of January 10, 2007 Technical Conference

8 OTHER ISSUES

8.1 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the NGEIR (EB-2005-0551) proceeding will be appropriately captured and reflected in this proceeding?

(Complete Settlement)

There is an agreement to settle this issue as follows:

All parties agree that the implications of the Board's decisions in the NGEIR (EB-2005-0551) proceeding have been captured in the Company's filing in this proceeding. This agreement is subject to the stipulation that certain parties have initiated Motions for Review of the Board's decisions in the NGEIR proceeding which, if successful, could require the Company to make consequential adjustments to its rates, including (without limitation) Rate 316.

The Company's obligations under the NGEIR Settlement Proposal pertaining to whether and when an automated solution should be developed and put in place remain in full force and effect.

Every three months the Company will provide to stakeholders a report on the number of customers that have committed to migrate and have migrated to the new unbundled Rates 300 and 315. If, at any time during the Test Year, 20 customers have committed to take EGD's unbundled rates, the Company will undertake a survey, using the least cost approach, to evaluate demand for unbundled Rates 300 and 315, and assess and report on the timing for development of an automated solution and accommodating additional customers through the manual solution within 90 days after the Company's 20th customer has committed to migrate to the new unbundled rates. If, at that time, the Company decides to proceed with a manual solution, it will continue to provide customers with a quarterly report on the status of migration including feedback from customers on the potential for future migration. The parties agree that the Company's costs associated with preparing and administering the survey will be recorded in the 2007 Unbundled Rate Implementation Cost Deferral Account. The parties further agree they will support recovery by the Company of the reasonably incurred survey costs in the 2007 Unbundled Rate Implementation Cost Deferral

Account on the understanding that the Company will seek to have all reasonably incurred costs recovered from large volume customers.

In order to allow customers to take advantage of the new Rate 300 and Rate 315, customers will have the opportunity to migrate to Rate 300 and 315 at all times during the Test Year until the point in time when 20 customers have migrated to the rate 300 series rates. Subject to the conditions of the Company's Early Termination Policy, the Company will permit migrating customers to terminate their bundled rate contracts early, on the understanding that customers will true up any imbalances in their existing contracts as per the provisions of the Company's Early Termination Policy.

If the survey results indicate that significantly more than 20 customers are prepared to commit to migrate, then the Company will undertake to develop an automated solution. If a smaller number of customers are prepared to commit to migrate, then the Company will conduct an analysis comparing the incremental cost of supporting incremental customers' activities and transactions using the manual solution versus the costs of an automated solution. The goal of the analysis will be to determine if it is feasible to expand the manual solution (and at what cost) versus the cost of an automated solution. Should an automated solution be required, the parties agree that the Company record associated costs in the Unbundled Rate Implementation Cost Deferral Account as per the NGEIR Settlement Proposal EB-2005-0551, Ex. S-1-1, p. 33.

If a manual solution permits more than 20 customers to migrate during the Test Year, any such additional spots will be implemented in a manner that is consistent with section 4(g) of the Settlement Agreement in EB-2005-0551 whereby 50% of the additional spots will be allocated to interested customers who will benefit the most from the service from a distribution rate perspective, and 50% of the additional spots will be allocated to interested customers entitled to subscribe for the service on the basis of a lottery system.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue except VECC which takes no position and did not participate in discussion on the issues discussed after the second paragraph above.

Evidence: The evidence in relation to this issue includes the following:

I-19-1 to 3	TransAlta Interrogatories 1 to 3
I-1-78 to 79	Board Staff Interrogatories 78 to 79
I-12-5 to 6	OAPPA Interrogatories 5 to 6

I-20-1	TransCanada Interrogatory 1

8.2 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the DSM (EB-2006-0021) proceeding will be appropriately captured and reflected in this proceeding?

(Complete Settlement)

There is an agreement to settle this issue as follows:

All parties agree that the implications of the Board's decisions in the DSM (EB-2006-0021) proceeding have been captured in the Company's filing in this proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

I-1-80 to 81	Board Staff Interrogatories 80 to 81
I-9-21 to 22	IGUA Interrogatories 21 to 22
I-24-76	VECC Interrogatory 76

9 RATE IMPLEMENTATION

9.1 How should the Board deal with any revenue deficiency applicable from January 1, 2007 to the date that the Board's decision is implemented?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

Parties agree that the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. Parties agree with and support the Company's proposal to recover the full $26.0 million through (i) increased annualized rates for the remainder of the Test Year; and (ii) the use of a rate rider over the nine remaining months of the Test Year to recover the remaining balance of the $26.0 million. Intervenors agree that no issue or objection will be raised around whether any part of this $26.0 million is unrecoverable because it relates to the time period between January 1, 2007 and April 1, 2007.

There is no agreement as to whether or how the Company can recover any revenue deficiency in excess of $26.0 million.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties except Schools accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

A1-2-1	Application
I-1-82	Board Staff Interrogatory 82
I-16-62 to 53	SEC Interrogatories 62 to 63

9.2 Should the Board set interim rates, effective January 1, 2007, to allow Enbridge to begin to recover its prospective revenue deficiency?

(Complete Settlement)

There is an agreement to settle this issue as follows:

This issue is no longer relevant, since the January 1, 2007 date has passed.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

A1-2-1	Application
I-1-83 to 84	Board Staff Interrogatories 83 to 84
I-16-64 to 65	SEC Interrogatories 64 to 65

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
ACTUAL BALANCES

Line No.	Account Description	Account Acronym	Col. 1 Actual at December 31, 2006 Principal ($000's)	Col. 2 Actual at December 31, 2006 Interest ($000's)	Col. 3 Accounts Agreed to be cleared with Final Rate Order Actual Balances at December 31, 2006 Principal ($000's)	Col. 4 Accounts Agreed to be cleared with Final Rate Order Actual Balances at December 31, 2006 Interest ($000's)	
	Non Commodity Related Accounts for One Time Rate Clearance						
1.	Demand Side Management Account	2006 DSMVA	374.7	(39.4)	-	-	
2.	Demand Side Management Account	2005 DSMVA	697.5	(9.7)	-	-	
3.	Demand Side Management Account	2004 DSMVA	2,013.9	149.1	2,013.9	149.1	
4.	Lost Revenue Adjustment Mechanism	2006 LRAM	-	-	-	-	
5.	Lost Revenue Adjustment Mechanism	2005 LRAM	-	-	-	-	
6.	Lost Revenue Adjustment Mechanism	2004 LRAM	(587.9)	13.6	(587.9)	13.6	
7.	Shared Savings Mechanism	2006 SSMVA	-	-	-	-	
8.	Shared Savings Mechanism	2005 SSMVA	-	-	-	-	
9.	Shared Savings Mechanism	2004 SSMVA	-	-	-	-	
10.	Class Action Suit D/A	2006 CASDA	23,514.2	117.1	-	-	
11.	Deferred Rebate Account	2006 DRA	(1,904.7)	(103.5)	(1,904.7)	(103.5)	
12.	Debt Redemption D/A	2006 DRDA	-	-	-	-	
13.	Ontario Hearing Costs V/A	2006 OHCVA	(612.8)	-	(612.8)	-	
14.	Manufactured Gas Plant D/A	2006 MGPDA	39.0	0.7	-	-	
15.	Electric Program Earnings Sharing D/A	2006 EPESDA	(175.1)	-	-	-	
16.	Corporate Cost Allocation	2006 CCAMDA	623.7	0.6	-	-	
17.	Unbundled Rate Implementation Cost D/A	2006 URICDA	480.5	-	-	-	
18.	Alliance/Vector Appeal Costs D/A	2006 AVACDA	529.2	17.3	-	-	
19.	Total Non Commodity Related Accounts for One Time Rate Clearance		24,992.2	145.8	(1,091.5)	59.2	
	Commodity Related Accounts for One Time Rate Clearance						
20.	2006 Purchased Gas V/A	2006 PGVA	(125,122.4)	(2,237.9)	-	-	a)
21.	2006 Transactional Services D/A	2006 TSDA	(7,508.8)	(15.5)	(7,508.8)	(15.5)	
22.	2006 Unaccounted for Gas V/A	2006 UAFVA	(11,739.1)	-	(11,739.1)	-	
23.	2006 Union Gas D/A	2006 UGDA	(2,919.3)	49.8	(2,919.3)	49.8	
24.	Total Commodity Related Accounts for One Time Rate Clearance		(147,289.6)	(2,203.6)	(22,167.2)	34.3	
25.	Total Deferral and Variance Accounts for One Time Rate Clearance		(122,297.4)	(2,057.8)	(23,258.7)	93.5	
	Non Commodity Related Accounts for Rate Base and Ongoing Rates Treatment						
26.	Gas Distribution Access Rule Costs D/A	2006 GDARCDA	7,923.3	62.1	-	-	b)
27.	Gas Distribution Access Rule Costs D/A	2005 GDARCDA	406.0	29.2	-	-	b)
28.	Gas Supply Risk Management Program D/A	2006 GSRMPDA	691.5	-	-	-	b)
29.	Total Deferral and Variance Accounts for Rate Base and Ongoing Rates Treatment		9,020.8	91.3	-	-	

Note: a) PGVA and related adjustments to be handled as part of April 2007 QRAM.

Note: b) These accounts would be required to be closed into rate base, with associated revenue requirement impacts, pending the hearing review and any eventual Board Approval.

EGD 2007 ADR PROPOSAL
BASED ON REVENUE DEFICIENCY OF $26 MILLION
FINAL

Rate Class	Impacts Relative to July 1, 2006 T-service Rates: Revenue to Cost Ratios 2007	Revenue to Cost Ratios 2006	Over/Under Contribution 2007	Over/Under Contribution 2006	Average Rate Impact T-Service	Impact Relative to January 1, 2007 T-service Rates: Average Rate Impact T-Service	TCPL Phase In Contribution
			$/M	$/M			$/M
1	1.01	1.01	10.35	8.75	2.07%	2.08%	5.01
6	1.01	1.01	5.06	4.19	0.66%	0.67%	4.89
9	0.69	0.69	-0.47	-0.59	6.44%	6.45%	0.00
100	0.97	0.98	-3.48	-2.92	1.91%	1.92%	0.00
110	1.01	1.01	0.38	0.33	-0.85%	-0.84%	0.00
115	0.90	0.90	-4.18	-5.49	0.96%	0.97%	-5.97
135	0.87	0.87	-0.28	-0.33	1.25%	1.25%	-0.60
145	0.97	1.03	-0.49	0.42	1.62%	1.63%	0.00
170	0.81	0.89	-4.98	-3.48	1.76%	1.76%	-3.20
200	0.98	0.98	-0.22	-0.20	4.60%	4.60%	0.00

Note: 2006 and 2007 Over/Under Contributions need to be adjusted by the TCPL phase in contribution amount to reflect the post October 1, 2007 situation.

EGD 2007 ADR PROPOSAL
BASED ON REVENUE DEFICIENCY OF $82.1 MILLION

Rate Class	Revenue to Cost Ratios 2007	Revenue to Cost Ratios 2006	Over/Under Contribution 2007	Over/Under Contribution 2006	Average Rate Impact T-Service	TCPL Phase In Contribution
			$/M	$/M		$/M
1	1.01	1.01	9.35	8.75	6.28%	5.01
6	1.01	1.01	5.42	4.19	4.52%	4.89
9	0.70	0.69	-0.48	-0.59	13.19%	0.00
100	0.98	0.98	-2.98	-2.92	5.48%	0.00
110	1.01	1.01	0.43	0.33	1.04%	0.00
115	0.90	0.90	-4.18	-5.49	1.96%	-5.97
135	0.87	0.87	-0.28	-0.33	2.54%	-0.60
145	0.97	1.03	-0.48	0.42	4.08%	0.00
170	0.82	0.89	-4.82	-3.48	4.24%	-3.20
	0.00		0.00			
200	0.98	0.98	-0.16	-0.20	7.70%	0.00

Note: 2006 and 2007 Over/Under Contributions need to be adjusted by the TCPL phase in contribution amount to reflect the post October 1, 2007 situation.

SUPPLEMENTARY SETTLEMENT PROPOSAL : ISSUE 7.5

The issues related to Issue 7.5 ("Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?") have been the subject of the ongoing Open Bill Consultative. Parties have been able to come to an agreement to settle aspects of this issue.

This incomplete settlement, if approved by the Board, will be added to the Settlement Proposal (Ex. N1-1-1) approved by the Board on January 29, 2007 (the "January 29th Settlement Proposal") and the provisions of this incomplete settlement will supersede the reference at page 43 of 47 of the January 29th Settlement Proposal which states that there is no settlement of Issue 7.5.

Parties agree that the provisions of the Introduction and Overview sections of the January 29th Settlement Proposal apply to this Supplementary Settlement Proposal, except for (i) the chart of settled issues, which does not reflect this incomplete settlement of Issue 7.5; and (ii) any references to revenue deficiency and rate impact of the settlement, which would have to be changed to reflect the incremental financial impact of this Supplementary Settlement Proposal.

With that preamble, the following section represents the incomplete settlement that has been agreed upon.

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as follows:

The parties agree to settle the third party billing component ("Billing Services") of Issue 7.5 Open Bill Access on the basis that the Company can proceed with the Billing Services on the following terms:

1. ***Compliance with Board Directive.*** All parties accept the Company's decision to respond to the Board's directive in EB-2005-0001 in two stages: an interim solution, using the Company's existing CIS, and a comprehensive solution, using the Company's planned new CIS. This settlement constitutes the interim solution until otherwise ordered by the Board in the Board review referred to in #2 below. Subject to the

presentation to the Board of the comprehensive solution, discussed in #2 below, all parties agree that this settlement constitutes an appropriate response to the Board's directive.

2. ***Comprehensive Solution.*** The Company agrees that it will file an application to the Board prior to the end of 2008 proposing the comprehensive Billing Services offering. Such application should include: a) a detailed report on the experience with the interim solution, b) any available consultants' reports with respect to costing and/or market pricing, c) the results of any customer communications activities and any customer or industry surveys, d) minutes and/or reports of the activities of the stakeholder committee referred to in #8 below, and e) the Company's proposal on whether the Billing Services should continue, and if so on what terms. Without limiting the generality of the foregoing, the Company's proposal may include changes to pricing, costing, shareholder incentive, and any other aspects of the Billing Services. In the event that in the Company's application the Company or any party proposes that the Billing Services should not continue, that party must also propose a reasonable transition period to reflect the time required for anyone using the Billing Services to shift to alternate billing arrangements. Nothing in this settlement implies that any party admits to either the relevance or the appropriate weight to be given to any particular evidence in this subsequent application, and all parties will be free to argue as they see fit with respect to any proposed evidence.

3. ***Pricing.*** During the interim period, but at least until December 31, 2008 parties accept the prices proposed by the Company, $0.829 for shared bills and $1.389 for standalone bills. All participants using the Billing Services will pay the same prices for the same services. The parties agree that prices for the Billing Services and any changes from time to time to the rules relating to the OBSDA referred to in #4 below must be approved by the Board.

4. ***Startup Costs.*** The shareholder will bear the startup and bill re-design costs associated with the Billing Services but will be allowed to recover 4 cents/bill from the Open Bill Service Deferral Account (OBSDA) over a two year period until the costs are recovered. The shareholder will not bear the costs associated with adding the Billing Services to the new CIS. The latter costs will be included in the costs of the Billing Services and recovered in revenues from the service.

5. ***Ratepayer Benefit.*** Subject to the shareholder incentive, set forth below, all net benefits, whether through mitigation of common costs, or net profits from the OBA services, will accrue to the benefit of the ratepayers. The Company agrees to include in its 2007 revenue requirement a net benefit of the service of $5.389 million. This number is derived from calculations /u found in JT.5, as updated to reflect this settlement. To be sure, all parties also agree If the net benefit of the service is greater or less than the amount included in rates, the difference will be credited or debited, as the case may be, to a new variance account, the Open Bill Access Variance Account (OBAVA) and refunded or charged to ratepayers in the following year. The net benefit shall be calculated as the total revenues from Billing Services, less

   a. the incremental costs to deliver those services;
   b. the amount referred to in #4 above; and,
   c. the shareholder incentive referred to in #6 below.

6. ***Shareholder Incentive.*** The Company will receive no incentive for Billing Services provided to any affiliate of the Company. For the Billing Services by any other person, the Company will be paid a commission as follows subject to an annual maximum calculated as 50% of the program's net margin:
   a. With respect to any bill on which Direct Energy (which for all purposes of these terms should be interpreted as including any successor to Direct Energy's water heater business) is the sole third party billing entity, $0.02 per bill;

   b. With respect to any bill on which there is any third party billing entity charge other than Direct Energy on the bill:

      i. $0.10 per bill in any month that the Billing Services service has only one active billing entity other than affiliates or Direct Energy;
      ii. $0.15 per bill in any month that the Billing Services service has two active billing entities other than affiliates or Direct Energy;
      iii. $0.20 per bill in any month that the Billing Services service has three active billing entities other than affiliates or Direct Energy;
      iv. $0.25 per bill in any month that the Billing Services service has more than three active billing entities other than affiliates or Direct Energy;

An entity will only be considered an "active billing entity" in any month in which it is billing products or services on at least 500 EGD bills.

7. ***Costing and Pricing Studies:*** The Company agrees that it will retain an independent consultant or consultants to undertake costing and pricing analyses for the Billing Services. The consultant's work will include assistance in determining a market price, and a review and analysis of the incremental and fully-allocated costs of these services. The Company will solicit the stakeholder group's input on the independent consultant(s), and statement of work for those consultant(s), but the Company will retain the right to make the final selection and define the terms of the reference. The cost of these studies will be included in the OBSDA.

8. ***Stakeholder Input.*** The Company will establish a stakeholder committee that includes users of the Billing Services, as well as ratepayer and industry representatives, to review the rules associated with participation in Billing Services. All parties to the agreement will be invited to become members of the stakeholder committee. The committee will meet from time to time as required to consider changes to the rules. Any changes to the rules that materially change the nature of the service will be reviewed by the stakeholder committee and reported to the Board to determine if their approval is required. The stakeholder committee will also be solicited for input into the Company's proposed communications plan, and other issues as they arise.

9. ***Affiliate Participation.*** Affiliates of the Company (including for the purpose of this settlement related parties such as limited partnerships or trusts that are not technically affiliates) may use the Billing Services on the same terms as any other third party biller. However, all parties agree with the principle that the Billing Services should be implemented in a manner that avoids ratepayer and/or consumer confusion, and, to the extent possible, prevents any participant from gaining any unfair market advantage by reason of their association with the utility, if any. The Company agrees that during the interim period it will implement such measures as may be necessary to achieve this principle, including but not limited to including in the Billing Services and enforcing in a commercially reasonable manner the following service rules::

   (a) No person, whether affiliate or otherwise, may use or associate itself with any name or logo on the bill that is the same as, similar to, or confusing with any name or logo that is associated with the Company (e.g. the "Enbridge" name and swirl logo).

(b) No person may use the Billing Services in an abusive or unfair manner in that it deliberately creates the impression that it has a preferred position relative to other market participants because of its relationship with the utility.

Notwithstanding, these restrictions in no way shape or form creates any future precedent to rely upon regarding the use of the Enbridge name or logo.

The parties acknowledge their mutual intention to bring issues with respect to affiliate participation to the stakeholder committee for resolution, but this statement will not limit any rights any party may have, whether under the Affiliate Relationships Code or otherwise, to have disputes resolved in any forum.

10. ***EnergyLink™ Relevance.*** If the Board in this proceeding approves the EnergyLink™ program proposed by the Company, the parties agree that whether a company is an EnergyLink™ participant or not will not affect whether that company can use the Billing Services, nor the rules or conditions under which they use the service.

11. ***Information.*** The Company will develop with input from the stakeholder committee an appropriate customer communication plan specific to Billing Services The Company shall provide to the Board and make available to all parties to this settlement agreement a report that includes revenues from Billing Services, and the costs of the services on a fully-allocated basis,an incremental basis and in a manner when known that is consistent with the methodology recommended in the study noted in paragraph 7, to the extent that this is different .

12. ***Logos and Bill Messaging.*** Logos and bill messaging will be provided to all participants in the Billing Services at no charge to facilitate entry of new users and help consumers differentiate the various parties with amounts billed on the EGD bill. Any provision of logos and bill messaging for the Billing Services will apply in the same manner to commodity vendors using the ABC Services for a reasonable charge, but commodity messaging will not be allowed unless EGD or one of its affiliates starts to market system gas.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Energy Probe, IGUA, OAPPA, Superior, TransAlta, TransCanada and Union Gas,

Approval: All participating parties accept and agree with the proposed settlement of this issue except that GEC and Pollution Probe reserve the right to pursue in the Hearing whether the Board should order that third parties not be allowed to use the Billing Services for the billing of specific products on the basis of their environmental attributes.

Evidence: The evidence in relation to this issue includes the following:

D1-11-1	Open Bill Access
D1-11-2	Statement of Principles, Objectives and Operating Arrangements for the Consultation Process for Enbridge Gas Distribution's Open Bill Access Proposal
D1-11-3	Open Bill Access Consultative Process
D1-11-4	Meeting Minutes
D1-11-5	Third Party Access Report
D1-11-6	Open Bill Access Update
D1-11-7	Summary Notes from Consultative Meeting on Wednesday July 26, 2006
D1-11-8	Open Bull Access Update – July 26th, 2006
D1-11-9	Summary Notes from Consultative Meeting on Tuesday November 14th, 2006
D1-11-10	Presentation – Consultative Meeting on Tuesday November 14th, 2006
D1-11-11	Open Bill Access Standard Bill Service Consultative November 14th, 2006
D1-11-12	Bill Insert Agreement
D1-11-13	Open Bill Standard Bill Service Description – Meeting November 14th, 2006 – Additional Request for Information
D1-11-14	Bill Inserts
D1-11-15	Bill Insert Agreement Draft
D1-11-16	Initial Draft for Discussion Binding request for Bids – Third Party Bill Inserts for 2007
D1-11-17	Presentation – Consultative Meeting on November 23rd, 2006
D1-11-18	Open Bill Access – Summary Notes from Consultative Meeting on November 23rd, 2006

D1-11-19	Presentation – November 30th, 2006
D1-11-20	Criteria for Bill Inserts
D1-11-21	Open Bill Access – Summary Notes from Conference Call between EGD, Intervenors, and Consultants on Friday, December 1st, 2006
D1-11-22	Shared Bill Benefit Calculation
D1-11-23	Presentation – December 5th, 2006 Corrected Forecast
D1-11-24	Bill Inserts
D1-11-25	Bill Inserts
D1-11-26	Bill Inserts
D1-11-27	Request for Binding Bids – 2007 Third Party Bill Insert Service
D1-11-28	Binding Service Request and Bid Form – 2007 Third Party Bill Insert Service
D1-11-29	Third Party Access to the Bill Customer Communication Plan
D1-11-30	Billing Insert Customer Communication Plan
I-1-74 to 77	Board Staff Interrogatories 74 to 77
I-2-52	CCC Interrogatory 52
I-4-1 to 12	Direct Energy Interrogatories 1 to 12
I-16-60 to 61	SEC Interrogatories 60 to 61
I-18-1 to 5	Superior Interrogatories 1 to 5
I-22-1 to 5	Union Energy Interrogatories 1 to 5
I-24-74 to 75	VECC Interrogatories 74 to 75
I-26-12 to 20	HVAC Interrogatories 12 to 20
L-4-1	Evidence of Direct Energy
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-1 to 35	Enbridge Gas Distribution Interrogatories of Union Energy 1 to 35
I-29-1 to 5	Enbridge Gas Distribution Interrogatories of Direct Energy 1 to 5
I-30-22 to 24	Enbridge Gas Distribution Interrogatories of HVAC 22 to 24
I-32-1 to 5	HVAC Interrogatories of Direct Energy 1 to 5
I-33-1 to 12	Superior Energy Management Interrogatories 1 to 12
I-34-1 to 21	Union Energy Interrogatories of Direct Energy 1 to 21
I-35-1 to 11	Direct Energy Interrogatories of Union Energy 1 to 11
I-36-1 to 16	Direct Energy Interrogatories of HVAC 1 to 16
	Transcript of January 10, 2007 Technical Conference
JT1-JT22	Undertakings from January 10, 2007 Technical Conference

SUPPLEMENTARY SETTLEMENT PROPOSAL : ISSUE 7.5

The issues related to Issue 7.5 ("Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?") have been the subject of the ongoing Open Bill Consultative. Parties have been able to come to an agreement to settle aspects of this issue.

This incomplete settlement, if approved by the Board, will be added to the Settlement Proposal (Ex. N1-1-1) approved by the Board on January 29, 2007 (the "January 29th Settlement Proposal") and the provisions of this incomplete settlement will supersede the reference at page 43 of 47 of the January 29th Settlement Proposal which states that there is no settlement of Issue 7.5.

Parties agree that the provisions of the Introduction and Overview sections of the January 29th Settlement Proposal apply to this Supplementary Settlement Proposal, except for (i) the chart of settled issues, which does not reflect this incomplete settlement of Issue 7.5; and (ii) any references to revenue deficiency and rate impact of the settlement, which would have to be changed to reflect the incremental financial impact of this Supplementary Settlement Proposal.

With that preamble, the following section represents the incomplete settlement that has been agreed upon.

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?

(Incomplete Settlement)

There is an agreement of some parties to settle aspects of this issue, as follows:

<u>Proposed Billing Insert Settlement</u>

The parties agree to settle the billing insert ("Insert Service") component of Issue 7.5 Open Bill Access on the basis that the Company can proceed with the Insert Service on the following terms:

1. ***Compliance with Board Directive.*** All parties accept the Company's decision to respond to the Board's directive in EB-2005-0001 in two stages: an interim solution, using the Company's existing CIS, and a comprehensive solution, using the Company's planned new CIS. This settlement constitutes

the interim solution until otherwise ordered by the Board in the Board review referred to in #2 below. Subject to the presentation to the Board of the comprehensive solution, discussed in #2 below, all parties agree that this settlement constitutes an appropriate response to the Board's directive as it pertains to bill inserts.

2. ***Comprehensive Solution.*** The Company agrees that it will file an application to the Board prior to the end of 2008 proposing the comprehensive Billing Insert Service offering. Such application should include: a) a detailed report on the experience with the interim solution, b) any available consultants' reports with respect to costing and/or market pricing, c) the results of any customer communications activities and any customer or industry surveys, d) minutes and/or reports of the activities of the stakeholder committee referred to in #8 below, and e) the Company's proposal on whether the Insert Service should continue, and if so on what terms. Without limiting the generality of the foregoing, the Company's proposal may include changes to pricing, costing, shareholder incentive, and any other aspects of the Insert Service. Nothing in this settlement implies that any party admits to either the relevance or the appropriate weight to be given to any particular evidence in this subsequent application, and all parties will be free to argue as they see fit with respect to any proposed evidence.

3. ***Pricing.*** For the interim period of 2007 and 2008, the Company agrees to reduce the minimum bids for bill inserts by one cent resulting in an average insert charge of 4 cents. For greater clarity, there shall be no right of first refusal for parties using the Company's Insert Service. The parties agree that prices for the Insert Service, and any changes thereto from time to time, must be approved by the Board.

4. ***Costing and Pricing. T***he Company agrees that it will retain an independent consultant to undertake a costing and pricing analysis for the Bill Insert Service for the comprehensive period. The consultant's work will include assistance in determining a market price, and a review and analysis of the incremental and fully-allocated costs of these services for the new CIS. The Company will solicit the stakeholder group's input on the independent consultant, and statement of work for that consultant, but the Company will retain the right to make the final selection and define the terms of the reference. The cost of this study will be included in the Open Bill Service Deferral Account (OBSDA).

5. ***Startup Costs.*** The shareholder will record the startup costs associated with the Insert Service in 2007 in the OBSDA. The startup costs associated with

adding the Insert Service to the new CIS will be included in the costs of the Insert Service and recovered in revenues from the service.

6. ***Ratepayer Benefit.*** The Company agrees to record the costs and revenues from the Insert Service in 2007 in the OBSDA and that the net proceeds will be shared 50/50. The parties agree that the shareholder incentive mechanism for Insert Service may need to be revised after the interim period and after the cost/price review to be consistent with the Board's rules for natural gas incentive regulation.

7. ***Inserts.*** Bill inserts would be allowed as proposed by EGD but revised to limit the number of external inserts to five (5) when safety inserts are scheduled. In all months, two inserts would be reserved for parties wishing to purchase bill inserts in a limited geographic area based on price per insert bidding.

8. ***Stakeholder Input.*** The Company will establish a stakeholder committee that includes users of the Insert Service, as well as ratepayer and industry representatives, to review the rules associated with participation in the Insert Services. All parties to the agreement will be invited to become members of the stakeholder committee. The committee will meet from time to time as required to consider changes to the rules. Any changes to the rules that materially change the nature of the service will be reviewed by the stakeholder committee and reported to the Board to determine if their approval is required. The stakeholder committee will also be solicited for input into the Company's proposed communications plans, and other issues as they arise. To ensure that consumer interests are being addressed, EGD will conduct focus groups and customer surveys on inserts as soon as possible in 2007 and report the findings to the stakeholder committee to determine if remedial action is required. EGD will also prescreen insert users and review the content of their bill inserts to ensure proper use of its billing envelope.

9. ***Problem Resolution.*** If the revised bidding and allocation processes restrict access in three consecutive months or the number of customer complaints on inserts increases significantly in the first two months of operation, the stakeholder committee would be convened to address the concern(s), and if the problem cannot be resolved within two (2) additional months that aspect of the Insert Service would be discontinued until the problem is addressed.

10. ***Affiliate Participation.*** Affiliates of the Company (including for the purpose of this settlement related parties such as limited partnerships or trusts that are

not technically affiliates) may use the Insert Service on the same terms as any other third party biller. However, all parties agree with the principle that the Insert Service should be implemented in a manner that avoids ratepayer and/or consumer confusion, and, to the extent possible, prevents any participant from gaining any unfair market advantage by reason of their association with the utility, if any. The Company agrees that during the interim period it will implement such measures as may be necessary to achieve this principle, including but not limited to including in the Insert Services and enforcing in a commercially reasonable manner the following service rules::

(a) No person, whether affiliate or otherwise, may use or associate itself with any name or logo in the billing envelope that is the same as, similar to, or confusing with any name or logo that is associated with the Company (e.g. the “Enbridge” name and swirl logo).

(b) No person may use the Insert Service in an abusive or unfair manner in that it deliberately creates the impression that it has a preferred position relative to other market participants because of its relationship with the utility.

Notwithstanding, these restrictions in no way shape or form creates any future precedent to rely upon regarding the use of the Enbridge name or logo.

The parties acknowledge their mutual intention to bring issues with respect to affiliate participation to the stakeholder committee for resolution, but this statement will not limit any rights any party may have, whether under the Affiliate Relationships Code or otherwise, to have disputes resolved in any forum.

11. ***EnergyLink™ Relevance.*** If the Board in this proceeding approves the EnergyLink*™* program proposed by the Company, the parties agree that whether a company is an EnergyLink*™* participant or not will not affect whether that company can use the Insert Service, nor the rules or conditions under which they use the service, subject to the restriction on use of the Enbridge name and logo as described in Item 10 above.

12. This agreement should not be construed as a settlement of any aspect of issue 3.4, including but not limited to, arguments to restrict the Company’s ability to promote EnergyLink *™* by bill insert or otherwise. Notwithstanding, the Company agrees to provide a schedule of EnergyLink *™* inserts on an annual basis, as part of the Binding Request for Bids process.

13. ***Commodity Marketing.*** Commodity bill inserts and marketing will not be allowed in the billing envelope unless EGD or one of its affiliates receives OEB approval to promote and/or market system gas commodity, in which case retailers, marketers and vendors will be allowed to promote and/or market their commodity offers through the Insert Service.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Energy Probe, IGUA, OAPPA, TransAlta, TransCanada and Union Gas,

Approval: Enbridge Gas Distribution, Direct Energy, OESLP and Union Energy accept and agree with this proposed settlement. HVAC, VECC and Schools do not agree with the proposed settlement. CCC opposes the proposed settlement in order that it may be permitted to pursue cross-examination on the issue. GEC and Pollution Probe reserve the right to pursue in the Hearing whether the Board should order that third parties not be allowed to use the Billing Services for the billing of specific products on the basis of their environmental attributes. Superior opposes the proposed settlement on the principle that it is not supportive of a settlement position that would allow for the Company to promote system gas through billing inserts as contemplated in Paragraph 13.

Evidence: The evidence in relation to this issue includes the following:

D1-11-1	Open Bill Access
D1-11-2	Statement of Principles, Objectives and Operating Arrangements for the Consultation Process for Enbridge Gas Distribution's Open Bill Access Proposal
D1-11-3	Open Bill Access Consultative Process
D1-11-4	Meeting Minutes
D1-11-5	Third Party Access Report
D1-11-6	Open Bill Access Update
D1-11-7	Summary Notes from Consultative Meeting on Wednesday July 26, 2006
D1-11-8	Open Bull Access Update – July 26th, 2006
D1-11-9	Summary Notes from Consultative Meeting on Tuesday November 14th, 2006
D1-11-10	Presentation – Consultative Meeting on Tuesday November 14th, 2006
D1-11-11	Open Bill Access Standard Bill Service Consultative November 14th, 2006
D1-11-12	Bill Insert Agreement
D1-11-13	Open Bill Standard Bill Service Description – Meeting November 14th, 2006 – Additional Request for Information
D1-11-14	Bill Inserts
D1-11-15	Bill Insert Agreement Draft
D1-11-16	Initial Draft for Discussion Binding request for Bids – Third Party Bill Inserts for 2007

D1-11-17	Presentation – Consultative Meeting on November 23rd, 2006
D1-11-18	Open Bill Access – Summary Notes from Consultative Meeting on November 23rd, 2006
D1-11-19	Presentation – November 30th, 2006
D1-11-20	Criteria for Bill Inserts
D1-11-21	Open Bill Access – Summary Notes from Conference Call between EGD, Intervenors, and Consultants on Friday, December 1st, 2006
D1-11-22	Shared Bill Benefit Calculation
D1-11-23	Presentation – December 5th, 2006 Corrected Forecast
D1-11-24	Bill Inserts
D1-11-25	Bill Inserts
D1-11-26	Bill Inserts
D1-11-27	Request for Binding Bids – 2007 Third Party Bill Insert Service
D1-11-28	Binding Service Request and Bid Form – 2007 Third Party Bill Insert Service
D1-11-29	Third Party Access to the Bill Customer Communication Plan
D1-11-30	Billing Insert Customer Communication Plan
I-1-74 to 77	Board Staff Interrogatories 74 to 77
I-2-52	CCC Interrogatory 52
I-4-1 to 12	Direct Energy Interrogatories 1 to 12
I-16-60 to 61	SEC Interrogatories 60 to 61
I-18-1 to 5	Superior Interrogatories 1 to 5
I-22-1 to 5	Union Energy Interrogatories 1 to 5
I-24-74 to 75	VECC Interrogatories 74 to 75
I-26-12 to 20	HVAC Interrogatories 12 to 20
L-4-1	Evidence of Direct Energy
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-1 to 35	Enbridge Gas Distribution Interrogatories of Union Energy 1 to 35
I-29-1 to 5	Enbridge Gas Distribution Interrogatories of Direct Energy 1 to 5
I-30-22 to 24	Enbridge Gas Distribution Interrogatories of HVAC 22 to 24
I-32-1 to 5	HVAC Interrogatories of Direct Energy 1 to 5
I-33-1 to 12	Superior Energy Management Interrogatories 1 to 12
I-34-1 to 21	Union Energy Interrogatories of Direct Energy 1 to 21
I-35-1 to 11	Direct Energy Interrogatories of Union Energy 1 to 11
I-36-1 to 16	Direct Energy Interrogatories of HVAC 1 to 16
	Transcript of January 10, 2007 Technical Conference
JT1-JT22	Undertakings from January 10, 2007 Technical Conference

SUPPLEMENTARY SETTLEMENT PROPOSAL : ISSUE 6.3

The Settlement Proposal filed as Exhibit N1, Tab 1, Schedule 1, which was approved by the Board on January 29, 2007 (the "January 29th, 2007 Settlement Proposal"), notes at page 39 of 47 that Issue 6.3 was an Incomplete Settlement. Specifically, there was no agreement on the Company's proposed Invoice Vendor Adjustment (IVA) charge. Discussions have continued in respect of the IVA charge and Parties have been able to come to an agreement to settle outstanding issues relating to the IVA charge.

If this Supplementary Settlement Proposal for the IVA charge is approved by the Board, it will be added to the January 29th, 2007 Settlement Proposal, and the provisions of this Supplementary Settlement Proposal will supersede the reference at page 39 of 47 of the January 29th, 2007 Settlement Proposal which states that there is No Settlement in respect of the IVA charge.

Parties agree that the provisions of the Introduction and Overview sections of the January 29th, 2007 Settlement Proposal apply to this Supplementary Settlement Proposal, except for the chart of settled issues, which does not reflect the complete settlement of Issue 6.3.

With this preamble, the following section represents the complete settlement that has been agreed upon.

6.3 Should the Board approve the contents of the Applicant's Rate Handbook?

(Complete Settlement)

There is an agreement to settle aspects of this issue, as follows:

The parties agree that:

1. The IVA charge by the Company will equal 0.65% of the absolute dollar value of the adjustment. Parties agree that this IVA charge is an interim measure that will apply from June 1, 2007 to December 31, 2007, and is without prejudice to any Party proposing an alternative IVA charge commencing January 1, 2008.

2. The Company will consult with interested parties and will consider the merits of bringing forward a different fee structure for a cost-based IVA charge. The Company will seek approval from the OEB for the new IVA charge, to be effective January 1, 2008.

3. Parties agree that the IVA charge is designed to only recover the costs incurred by the Company to provide this service. As a result, Parties agree that there is no need to adjust the revenue deficiency as a result of forecast IVA charge revenues and costs. The Company will provide parties with a summary of 2007 IVA charge revenues and costs subsequent to December 31, 2007.

***Participating Parties*:** All parties participated in the negotiation and settlement of this issue except Energy Probe, GEC, HVAC, LIEN, OAPPA, Pollution Probe, SEC, Superior, TransCanada, TransAlta, Union Energy and Union Gas.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue. Without limiting the generality of the Introduction to the Settlement Proposal, VECC's acceptance of this proposed settlement is without prejudice to it proposing that IVA charges be reviewed as part of the Board's generic review of the QRAM/System Gas. CCC, HVAC, IGUA, Energy Probe, SEC, and Union Energy take no position.

Evidence: The evidence in relation to this issue includes the following:

D1-10-2, plus attachment	Gas Distribution Access Rule
Tr. 5, pp. 68, 73-74	

SETTLEMENT PROPOSAL FOR CUSTOMER CARE AND CUSTOMER INFORMATION SYSTEM ("CIS") ISSUES

I. PREAMBLE

The following issues related to Enbridge Gas Distribution's Customer Care O&M and Customer Information System ("CIS") capital budgets, and related matters, have been among the subjects addressed as part of the ongoing Customer Care/CIS Consultative:

7.1 Has Enbridge complied with the direction, in the EB-2005-0001 Decision, to file in evidence the following Customer Care Support Cost information: all agreements between Enbridge and CWLP, ECSI or any other EI-related entity related to the provision of customer care or CIS; the Program Agreement between CWLP and Accenture, including any amendments or revisions; financial statements for ECSI and CWLP (historical, bridge and test year); the return analyses described in the decision? (D1-12-3)

7.2 What actions or decisions are required by the Board regarding items in the 2006 and 2007 capital budgets which might be duplicated in the upcoming application for a Regulatory Asset Account? (D1-10-1, p. 2/AppA)

7.3 Are the forecast costs of the new CIS system appropriate? (B1-5-1, p. 3)

7.4 What are the appropriate costs for CIS and Customer Care for 2007, including internal and transition costs? (D1-12-1, p. 2 and D3-2-1, p. 1)

As set out below, parties have been able to come to an agreement to settle these issues, as well as other matters related to Customer Care and CIS.

All aspects of this Supplementary Settlement Proposal are subject to approval by the Board. The parties to the settlement all agree that this Supplementary Settlement Proposal is a package: the individual aspects of this agreement are inextricably linked to one another and none of the parts of this settlement are severable. As such, there is no agreement among the parties to settle any aspect of the issues addressed in this Supplementary Settlement Proposal in isolation from the balance of the issues addressed herein. The parties agree, therefore, that in the event that the Board does not accept this Supplementary Settlement Proposal in its entirety, then (in accordance with the Board's Settlement Conference Guidelines) the Board will reject the

Supplementary Settlement Proposal in its entirety and proceed to hearing on all of the issues listed above.

This Supplementary Settlement Proposal, if approved by the Board, will be added to the Settlement Proposal (Ex. N1-1-1) approved by the Board on January 29, 2007 (the "January 29th Settlement Proposal") and the provisions of this Supplementary Settlement Proposal will supersede the references at pages 41 and 42 of the January 29th Settlement Proposal which state that there is no settlement of Issues 7.1 to 7.4.

If approved by the Board, this Supplementary Settlement Proposal will reduce the Company's revenue deficiency for the Test Year by approximately $24.2 million, from the $52.1 million remaining as the revenue deficiency in the Company's Application, after the Settlement Proposal (Ex. N1-1-1) revenue deficiency of $29.9 million was approved by the Board on January 29, 2007 (with $26.0 million thereof recoverable in interim rates effective April 1, 2007). The remaining revenue deficiency at issue in the Company's Application is now about $26.1 million[1], taking into account the fact that parties are agreeing in this Supplementary Settlement Proposal that the Company can recover a revenue deficiency of approximately $1.8 million in respect of customer care and CIS costs in the Test Year.[2] This $1.8 million Customer Care revenue deficiency, which is described below in more detail, is the result of extra costs from customer growth, offset by a reduction in bad debt costs.

Finally, although it is not set out expressly in the sections that follow, the parties agree that, as part of this settlement package, Issue 7.2 is resolved because the Regulatory Asset Account application is no longer necessary. The parties also agree that, in response to Issue 7.1, the Company has filed those materials stipulated in the Board's EB-2005-0001 Decision that are currently available. There are, however, some agreements associated with the Company's move away from CustomerWorks Limited Partnership ("CWLP"), including transition agreements with Accenture Business Services for Utilities ("ABSU")[3], that are not completed. Accordingly, at this time Issue 7.1 is partially resolved and the parties expect that it will be completely resolved when those agreements are finalized and filed.

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[1] Note that this does not include any impact of Supplementary Settlement Proposals related to bill access and IVA charges.

[2] The $1.8 million deficiency to be recovered for Customer Care is derived by starting with the customer care deficiency of $26 million, set out at lines 2 and 3 of the Table at Ex. N1-2-2, p. 2, and then subtracting $24.2 million, which is the agreed-upon revenue deficiency reduction that would result from approval of this Supplementary Settlement Proposal.

[3] For the purposes of this Supplementary Settlement Proposal, both Accenture Business Services for Utilities and Accenture Inc. will be referred to as "ABSU".

With that preamble, the following represents the settlement that has been agreed upon.

II INTRODUCTION

Beginning in 2000, Enbridge Gas Distribution Inc. ("Enbridge Gas Distribution" or the "Company") entered into a series of arrangements whereby CIS and Customer Care services were acquired through a related company, Enbridge Commercial Services Inc. ("ECSI"). ECSI subsequently entered into a limited partnership arrangement with Terasen Inc., CWLP, for the purpose of providing customer related business support and information technology services to utilities. Enbridge Gas Distribution entered into a new Customer Care services agreement with CWLP and consented to ECSI's assignment of its CIS service agreement to CWLP, both effective from January 1, 2002. In August 2002, CWLP entered into an agreement in writing with ABSU, hereinafter referred to as the "Program Agreement", whereby CWLP transferred certain assets and all operating personnel to ABSU, and ABSU agreed to provide Customer Care services, including CIS hosting services, on behalf of CWLP to Enbridge Gas Distribution and other utilities for the period that could be as long as 2002 to 2011 (inclusive) for amounts detailed in a Schedule to the Program Agreement. Since 2002, pursuant to the Program Agreement, ABSU has been performing the Customer Care and CIS services for the Company on behalf of CWLP.

A portion of the fees which the Company has paid to CWLP/ECSI to acquire CIS and Customer Care services was paid by CWLP/ECSI, ultimately, to Enbridge Gas Distribution's parent or other affiliates.

In a series of rate cases, the Intervenors expressed their objection to these arrangements, arguing that ratepayers should only be required to pay for CIS and Customer Care services at a market price or, failing a competitive process, at the cost of any affiliate, or related company, providing the services, including an appropriate return on such an endeavour. In the 2006 rate case decision, the Board agreed that what ABSU was paid to provide the services to Enbridge Gas Distribution for Customer Care and CIS services was relevant to the determination of the market prices for the services. The Board ultimately used CWLP revenue from Enbridge Gas Distribution, expressed as a proportion of CWLP's total revenues, as a tool to derive CWLP overearnings attributable to Enbridge Gas Distribution, and then, using the utility allowed return, the Board determined the amount recoverable from Enbridge Gas Distribution's ratepayers. The Board, in decisions in rate cases beginning in 2003 and culminating in Enbridge Gas Distribution's 2006 rates case, urged the Company to obtain CIS and Customer Care services by direct competitive tender which, in the Board's view, should exclude the right of first refusal in favour of CWLP.

Following the Decision with Reasons of the Board in EB-2005-0001, Enbridge Gas Distribution undertook to do the following:

1. Acquire a new Customer Information System (CIS) through a direct competitive tender;

2. Acquire Customer Care services through a direct competitive tender.

Enbridge Gas Distribution also convened a consultative process (the "Consultative") through which Intervenors could monitor and comment on these procurement processes. In light of the concern which Intervenors had, in past rate cases, expressed about Enbridge Gas Distribution's arrangements for acquiring CIS and Customer Care Services, the Intervenors wanted to be assured that the procurement processes were consistent, in all respects, with accepted industry standards, and that the arrangements resulting from the procurement processes will not result in amounts being paid by Enbridge Gas Distribution to CWLP, Enbridge Gas Distribution's affiliates, or its parent. Enbridge Gas Distribution convened the Consultative in part to give the Intervenors those assurances. To further ensure that the Consultative could achieve its goals, Intervenors were given access to independent expertise to advise them on the procurement processes and the results therefrom.

Through the Consultative, the Company informed Intervenors that CWLP has not indicated any intention to exercise its right of first refusal in respect of the new Customer Care or CIS services. CWLP/ABSU have now committed to include a clause in the transition agreements associated with the move to new service providers that will waive CWLP's right of first refusal when the transition agreements are signed.

The Company represents that, apart from the payments to be made by the Company to CWLP up to April 1, 2007, no more than $8.34 million in aggregate will be paid by any person to CWLP, ECSI, EI or any other related entity in relation to any Customer Care or CIS services included within this agreement and provided to Enbridge Gas Distribution by any person during the course of this agreement.

As a result of the work of the Consultative, Enbridge Gas Distribution and the Intervenors have been able to reach agreement on certain aspects of the procurement processes completed to date. The work of the Consultative is described in the pre-filed evidence of Mario Bauer, filed as Exhibit L-2.

The procurement processes will not be completed, with the selection of a new CIS and a new Customer Care service provider, until mid 2007. As a result, the cost of the new CIS and of the new Customer Care service provider cannot be estimated at this time. In addition, the prudence and cost consequences of the CIS and Customer Care arrangements cannot be determined until those arrangements have been finalized, which is expected to be in the first half of 2007. As well, the new CIS will not become operational until June 2009 and it is only at that time that final costs for the new CIS will be known. Finally, the shortlisted bidders for Customer Care services include ABSU and a third party, so there is the potential that a new service provider, other than ABSU, will be selected. The introduction of a Customer Care service provider, other than ABSU, will involve transition arrangements with ABSU and others in both 2007 and 2008, and the costs consequences and upper limits of those costs have been estimated. Final estimates of such costs cannot be made until a later date.

Within these practical constraints, the parties have settled Issues 7.1 through 7.4, which are the Customer Care and CIS issues in this EB-2006-0034 proceeding. The settlement necessarily reflects the fact that certain aspects of the CIS and Customer Care arrangements, including the final costs and contract terms, will not be known until later in 2007.

The parties have agreed that a placeholder amount will be used to establish the revenue requirement for Customer Care costs for 2007. The placeholder chosen is the cost-per-customer set by the Board in the EB-2005-0001 Decision, at $49.58. As a result of this settlement, the total Customer Care budget to be recovered in rates for 2007, including all internal and external costs (except for bad debt), and including all revenue requirement impacts of CIS, will be $90.8 million, plus an amount of $15.1 million representing the provision for uncollectible accounts.

The settlement includes provision for a "true-up" process to adjust the revenue requirement to reflect the prudent and reasonable forecast amounts resulting from the procurement processes, and to reflect the agreed-upon recovery of certain "transition" costs.

The parties believe that a six-year term, covering the period 2007 through 2012 inclusive, is the appropriate term over which to calculate the revenue requirement relating to Customer Care and CIS. The expected costs of CIS and Customer Care during that period may fluctuate year over year. The parties agree that the annual amounts included in rates should be smoothed, over the 2007-2012 term, to avoid swings in rates. The effect of the true-up process is (a) to capture any variance between the 2007 placeholder for Customer Care and CIS revenue requirement of $90.8 million and the normalized revenue requirement for 2007 and pay that variance to, or recover it from, the ratepayers in the 2008-2012 period, and (b) establish the component of the Company's revenue requirement relating to Customer Care and CIS (except bad debt) for the period 2007-2012, and smooth the rate impacts of that component over that period.

To reflect the settlement the parties have agreed upon a template (the "Template"), which sets out all of the relevant categories of expenses over the 2007 to 2012 period that relate to Customer Care and CIS (except for bad debt costs). The costs in a number of those categories can be established today, and the parties have therefore agreed to those amounts. However, some costs to be set out in the Template must be determined when the contract prices and other costs are known. For those costs, the parties have agreed to the parameters under which those costs will be calculated or forecast and then included in the true-up calculation.

As the parties anticipate the possibility of an incentive regulation ("IR") regime, the terms of which are expected to be established later in 2007, they believe that the true-up should occur at a time when the IR formula for the Company has been established. Once the contract for Customer Care services has been signed, and the terms of IR are known, which is expected to be in the fall of 2007, the parties have agreed that the true-up should take place, in accordance with the true-up rules set out in this Settlement Proposal and Appendix. Parties agree that adjustments may need to be made to aspects of this agreement in the event that the IR regime that, for the purposes of calculation, was assumed by the parties in creating the Template – ie. a price cap IR regime of five years in duration, beginning January 1, 2008 - is not established. Adjustments may need to be made to the normalization approach set out in the True-Up Rules (which are attached) to make it compatible with the IR model and formula that is approved for Enbridge Gas Distribution. Any such adjustments would not affect the total revenue requirement to be recovered over the term of this agreement, but they may impact upon the amount to be recovered in each year of the agreement under the normalization approach that is used.

Finally, the parties agree that the Consultative will continue to monitor the completion of the procurement process, up to and including reviewing the final terms of the contracts, and thereafter, the implementation of the CIS and Customer Care arrangements, which the parties agree will be no later than six months after the in-service date for the new CIS. As has been the case to date, the Intervenors involved in the Consultative agree that they will raise any concerns about the ongoing process, and the outcomes from that process, as soon as they have sufficient information to identify and communicate those concerns. If the Intervenors involved in the Consultative believe that they are not receiving sufficient information, they will advise the Company immediately. The parties agree that the Consultative will continue to work in a timely, responsive and reasonable manner until its mandate is completed. Finally, the parties agree that all costs of the Consultative, for as long as it continues, will be fully recoverable from ratepayers. Costs of the Consultative that are incurred in 2007 will be included in the already established 2007 Ontario Hearings Costs Variance Account (2007 OHCVA). Parties agree to support the continuation of appropriate deferral accounts in future years for the recording and disposition of future costs of the Consultative, unless these costs are included in the Company's regulatory O&M budget during the IR term.

II TERMS OF SETTLEMENT

Against that background, the parties have agreed as follows:

(A) 2007 O&M Customer Care costs

As noted above, certain of the anticipated costs associated with Customer Care during the period 2007 through 2012 will not be known until RFP processes currently being carried out by the Company are completed and market prices are identified. As a result, revenue requirement will be established for 2007 using a placeholder to calculate the Customer Care costs. The placeholder will be the Board-approved 2006 cost per customer of $49.58, times the projected number of customers in 2007, 1,831,283, to get a total Customer Care placeholder of $90.8 million for 2007.

The parties agree that projected bad debt costs (Provision for Uncollectible Accounts) of $15.1 million as filed by the Company shall be recoverable in rates in 2007. This agreement does not deal with bad debt costs beyond 2007; as a result, bad debt costs are not included in the True-Up calculation. For the period from 2008 to 2012, bad debt costs will be dealt with by the Board along with other O&M costs, separately from other Customer Care costs which are the subject of this agreement, in such other proceeding or proceedings as the Board may determine.

For the purposes of settlement, the Customer Care placeholder of $90.8 million plus bad debt costs of $15.1 million will replace the amounts in the Company's Application and pre-filed evidence which total $130.1 million, and are comprised of $101.6 million for Customer Care and CIS Service Charges, $3.4 million for Customer Care Internal Costs, $15.1 million for Provision for Uncollectibles and $10.0 million for transition costs (see Exhibit D1-2-1, p. 3, Table 1, lines 2 to 4 and Ex. D1-1-1, p. 1, Table 1, line 3). These internal and transition costs are addressed in the True-Up Rules which are attached as Appendix A.

As a result, the settlement of this item will reduce the Company's revenue deficiency for the Test Year by approximately $24.2 million, from the $52.1 million remaining as the revenue deficiency in the Company's Application, after the Settlement Proposal (Ex. N1-1-1) revenue deficiency of $29.9 million was approved by the Board on January 29, 2007 (with $26.0 million thereof recoverable in interim rates effective April 1, 2007). The remaining revenue deficiency at issue in the Company's Application is now about $26.1 million, taking into account the fact that parties are agreeing in this Supplementary Settlement Proposal that the Company can recover a revenue deficiency of approximately $1.8 million in respect of customer care and CIS costs in the Test Year (the amount that is the difference between the 2006 Board-approved budget of $104.1 million and the $105.9 million total amount for 2007 for Customer Care, CIS and bad debt costs). This $1.8 million Customer Care revenue deficiency can be derived by accounting for customer growth in F2007 over the previous year (the $49.58 placeholder is multiplied by 46,228, which is the forecast number of new customers in 2007) and adjusting for a reduction of $500,000 in bad debt costs, as compared to F2006.

(B) ***2007 Capital costs related to CIS***

The parties agree that any capital spending by the Company during the 2007 Test Year related to the new CIS shall be in addition to the Company's overall Board-approved capital budget of $300 million plus the costs of the Portlands Energy Centre LTC. This is consistent with the language in Issue 1.1 of the Settlement Proposal in this EB-2006-0034 proceeding, which was approved by the Board on January 29, 2007 and which stated that "[p]arties have reached a global settlement of all 2007 Rate Base issues, except for issues related to the capital budget for the new CIS system" (Ex. N1-1-1, p. 13). No capital expenditures in 2007 relating to the new CIS will be closed to rate base in 2007, and the new CIS will have no impact on 2007 rates.

(C) ***Selection process for new CIS and Customer Care service providers and Transition Plan***

As explained above in the Introduction section, it is anticipated that the selection of a new CIS and a new Customer Care service provider will occur in the second quarter of 2007, when the associated RFP processes are completed.

Once selections are made, contracts will have to be negotiated and settled with the chosen parties. At that time, some of the expected costs of the new CIS, and payments to be made to the new Customer Care service provider, will be established between Enbridge Gas Distribution and the service providers through contractual arrangements. The Consultative will continue to function until the completion of the procurement process, the implementation of those CIS and Customer Care arrangements and the completion of the true-up process described below. The Consultative will be involved with monitoring the selection process and reviewing the terms and prudence of the resulting contracts, including the reasonableness of their costs. Parties agree that the Consultative will continue to work in a timely, responsive and reasonable manner until its mandate is completed.

The selection processes for both the CIS and the Customer Care services RFPs are underway. At this point, the remaining shortlisted bidders for the Customer Care services include ABSU and a third party. The remaining shortlisted bidders for the system integrator component of the new CIS include ABSU and a third party. The parties have agreed that for the time period from January 1, 2007 to March 31, 2007, CWLP will continue to provide CIS and Customer Care services to Enbridge Gas Distribution. For the period commencing April 1, 2007 and concluding no later than September 30, 2008, Enbridge Gas Distribution is making arrangements with ABSU to provide the CIS and Customer Care services directly to Enbridge Gas Distribution, at least until the potential transition to new service providers is complete.

There are two types of transition costs addressed in this Supplementary Settlement Proposal: CIS transition costs and Customer Care transition costs.

The parties acknowledge and agree that all transition costs with respect to the new CIS are included in the $118.7 million capital cost of the new CIS (discussed below), whether or not ABSU is awarded the system integrator component of that project.

The parties further acknowledge and agree that, in the event that ABSU is chosen as the Customer Care service provider, there will be no transition costs associated with Customer Care services. In the event that the third party is chosen as the Customer Care service provider, then there will be transition costs associated with the move to the new service provider. Enbridge Gas Distribution has prepared, and has shared with the Consultative, a Transition Plan that sets out how Customer Care may be transitioned to a new service provider. The parties agree that there will be costs associated with any such transition, and that those costs are recoverable in the manner and amounts described in detail in the True-Up Rules at Appendix A. The Company agrees that it will keep the transition costs, and the transition time period, to a reasonable level while managing the risks associated with transition and ensuring that the ongoing provision of Customer Care services meets OEB-mandated service levels. In this regard, the Company agrees that while the maximum time period for transition to a new Customer Care service provider will be 18 months from April 1, 2007, it will make best efforts to shorten that time period. The Company will ensure that its arrangements with ABSU will allow the Company to direct ABSU to cease the provision of some or all Customer Care transition services before the end of 18 months and, as a result, to reduce the transition costs payable by Enbridge Gas Distribution to ABSU.

(D) ***<u>The True-Up process and Revenue Requirement for 2008 to 2012</u>***

(i) Overview

The parties agree that, on a date (the "True-Up Time") that is the later of (a) the date when the Company's Customer Care RFP is completed and the contract is signed, and

(b) the date when the Board's decision with respect to the duration, rules and formulae for IR that relate to Enbridge Gas Distribution is released, the parties will calculate a true-up and smoothing for the Customer Care amounts for 2007 to 2012, using the specific rules set forth in Appendix A to this Settlement Proposal (the "True-Up Rules").

As set out in more detail below in Appendix A, the amount of the Customer Care costs that are projected to be incurred by the Company during the 2007 to 2012 period, and which the Company will recover in rates, will be determined by the parties at the True-Up Time in accordance with the criteria specified in the True-Up Rules. The components of the Customer Care costs and revenue requirement are itemized in the "Customer Care and CIS Settlement Template" (already defined as the "Template"), which is attached to Appendix A.

It is the intention of the parties that the True-Up process will be used to determine the Customer Care amount for 2007 (the "Normalized 2007 Customer Care Revenue Requirement") that, when adjusted using the True-Up Rules for each year until 2012, will allow the Company to fully recover in rates the costs incurred in providing Customer Care services (including CIS) during the period from 2007 through 2012.

In the event that the parties are unable to agree on the amount of any component of the Normalized 2007 Customer Care Revenue Requirement or any number to be included in the Template, other than those numbers that are fixed by the terms of this agreement, then parties agree that the unresolved dispute will be determined by the Board in accordance with the criteria specified in the True-Up Rules. Specifically, if the parties have not agreed to the Normalized 2007 Customer Care Revenue Requirement within sixty days of the True-Up Time, they shall list the components of the calculation that are in dispute, and provide that list to the Board for determination in accordance with the criteria specified in the True-Up Rules.

The outcome of the True-Up process will be the subject of a separate application to the Board. That application will include, for Board approval, all numbers that are agreed upon and set in accordance with the True-Up Rules, as well as the list of the items remaining at issue to be determined by the Board.

(ii) 2007 Customer Care Variance Account

At True-Up Time, the Company will calculate the difference (the "2007 Customer Care Revenue Requirement Variance") between that amount of revenue requirement that is, pursuant to the True-Up Rules, recoverable for 2007 Customer Care costs (the Normalized 2007 Customer Care Revenue Requirement) and the placeholder of $90.8 million, and will credit or debit the 2007 Customer Care Revenue Requirement

Variance, as the case may be, to the 2007 Customer Care Variance Account. The balance in that account will be repaid to the ratepayers, or charged to the ratepayers, with interest, over the course of 2008 to 2012. The 2007 Customer Care Variance Account will be cleared in accordance with the True-Up Rules.

In order for effect to be given to this provision of this Settlement Proposal, parties agree that it is appropriate that a 2007 Customer Care Variance Account be created, and continued until 2012.

(iii) Revenue requirement for Customer Care costs between 2008 and 2012

The revenue requirement that the Company will be entitled to recover each year in respect of Customer Care costs (including CIS but not including bad debt) from 2008 to 2012 shall be the Normalized 2007 Customer Care Revenue Requirement, as adjusted for each year from 2008 to 2012 (inclusive) by the Incentive Regulation formula. The intention of the parties is that this will result in a relatively stable revenue requirement for CIS and Customer Care services over a five year period.

As set out above, and explained in the True-Up Rules, the "Normalized 2007 Customer Care Revenue Requirement" will be the amount that, when adjusted according to the True-Up Rules (including the rules for IR described as part of the True-Up Rules) for each year until 2012, will allow the Company to fully recover in rates the total of all forecast prudent and reasonable Customer Care costs (including CIS but not including bad debt) for the period from 2007 through 2012.

The parties agree that all O&M costs associated with Customer Care (except for bad debt costs), including O&M relating to the Company's proposed new CIS, are included in the calculation of Normalized 2007 Customer Care Revenue Requirement and therefore will be properly recovered in rates during the period 2007 through 2012 through the operation of the True-Up Rules.

The Company agrees that, once the outstanding items on the Template are determined, and completed, and, as a result, the Normalized 2007 Customer Care Revenue Requirement is established, the Company will not seek any adjustment to its rates or revenue requirement that is directly or indirectly based on changes in Customer Care costs during the term of this agreement. Intervenors similarly agree that they will not seek adjustments to the Company's rates or revenue requirement that is directly or indirectly based on changes in Customer Care costs. As expressed above, bad debt costs are not included as part of the Customer Care costs that are the subject of this agreement from 2008 to 2012.

Notwithstanding the limitations expressed in the preceding paragraph, the parties agree that in the event that new legislative or regulatory requirements, that are currently unknown and that are beyond the Company's control, are imposed on the Company, in the period up to and including 2012, and those requirements materially change the level of Customer Care costs, then any of the parties shall be entitled to make application to the Board for adjustments to rates or revenue requirement as appropriate. The materiality threshold that applies to this aspect of the agreement will be established at the IR proceeding. The parties agree that the rights conferred in this paragraph will be no greater than any rights to revisit any issue based on changes in legislative or regulatory requirements that are established as part of the IR rules that apply to the Company.

In order to give effect to certain aspects of the True-Up Rules, as detailed in Appendix A, parties agree that it is appropriate that 2007 and 2008 Customer Care Transition Costs Variance Accounts be created to track certain transition costs related to Customer Care. The transition costs to be tracked in these accounts relate to activities that ABSU and external contractors and internal resources will undertake to transfer knowledge and services to the new service provider. This will include such tasks as training, documentation and management of the vendors through the transition. The transition costs to be tracked in these accounts are subject to a maximum total amount of $11.1 million. The details of the 2007 and 2008 Customer Care Transition Costs Variance Accounts are set out below, as part of the True-Up Rules.

(iv) New CIS

As the Board is aware, the Company is planning to replace its current CIS service with a new CIS that will be owned by the Company. When this system is implemented, which is expected in 2009, its capital cost will be included as part of the Company's utility rate base. Through the Consultative process, and subject to an adjustment described below, the parties have agreed that a reasonable cost for this asset is $118.7 million, including procurement costs of $5.1 million. The parties agree that rates will be set during the period of this agreement on the basis of a CIS cost that will be no higher than $118.7 million. This $118.7 million budget consists of an amount of $42 million for system integrator contract costs, which are subject to a direct competitive tender process, and an amount of about $76.7 million which the Company will manage and control during the CIS procurement and implementation process.

All parties agree that the Company's revenue requirement associated with Customer Care activities for the 2007 to 2012 period will incorporate a portion of the cost for the new CIS of $118.7 million, including procurement costs of $5.1 million, as set out below. The procurement process that provides support for the reasonableness of this cost is described in the evidence of Mario Bauer (Exhibit L-2), and the CIS cost analysis attached thereto. The parties agree that this $118.7 million cost is subject to reduction in the event that the system integrator contract costs arrived at through the CIS procurement process are less than $42 million. In the event that the system integrator costs are $42 million or more, then the parties agree to the cost of $118.7 million for the completion of the Template and the term of this agreement.

While the revenue requirement attributable to CIS shown in Row 3 of the Template is not yet finalized, the parties agree upon the following:

1. As stated above, the parties agree upon the prudence of the CIS procurement process and the capital cost for the new CIS of $118.7 million, which includes procurement costs of $5.1 million.

2. The parties agree that the amounts to be recovered in rates will be reduced, if the system integrator contract costs arrived at through the CIS procurement process are less than $42 million.

3. Subject to the restrictions on CIS costs set forth in this agreement, there is agreement that all prudently incurred and reasonable costs associated with the new CIS, including return and income taxes, should be recoverable in rates, during the term of this agreement, and for the 10-year economic life of the new CIS assets.

4. The parties agree that the term of this agreement will be six years from 2007 to 2012, in order to enable the smoothing and managing of the recovery of the revenue requirement attributable to the new CIS during those years.

5. The parties agree that they support the decision to procure the new CIS as prudent, the inclusion of the new CIS in rate base in 2009, and the recovery of all amounts associated with the new CIS subject to the terms of this agreement. Subject to any adjustment that may be made to rate base as of December 31, 2012 to reflect the actual costs of the new CIS, as set forth below, the parties agree that, as of January 1, 2013, the amount included in opening rate base for the new CIS shall be its 2012 closing net book value of approximately $71.4 million.

6. The parties agree that, for rate-making purposes, the in-service date of the new CIS will be deemed to be July 1, 2009, regardless of the actual in-service date, and the rate base for the new CIS will be calculated in all respects as if it was brought into service on July 1, 2009.

7. The parties agree that, for rate-making purposes, CIS Capital Costs at the end of the term of this Agreement will be treated as follows:

    a. If the actual costs of the New CIS are less than $118.7 million, then the $71.4 million amount included in the January 1, 2013 opening rate base for the New CIS shall be appropriately adjusted downwards;

    b. No capital costs in addition to the amount of $118.7 million will be eligible for closure to rate base on January 1, 2013, unless Enbridge Gas Distribution then demonstrates the reasonableness and prudence of such additional costs; and on the further condition that the only additional amounts eligible for consideration will be confined to increases in the system integrator costs beyond the $42 million provision for those costs included within the budget of $118.7 million.

On this basis, and subject to later adjustment as described at point 2 above, the parties request the Board, as part of the approval of this Settlement Proposal, to approve the prudence and $118.7 million cost of the new CIS, which includes procurement costs of $5.1 million.

The parties agree that there are three, and only three, possible adjustments to be made later to the revenue requirement attributable to CIS for the period 2009 through 2012, as shown in Row 3 of the Template.

The first possible adjustment relates to the tax savings associated with the high Capital Cost Allowance (CCA) for IT hardware and software for the CIS asset. The high CCA produces substantial tax savings in the first two years of the asset's ten year life. The Company acknowledges and agrees that the ratepayers are to receive credit for the full value of these tax savings. The tax rules provide that Enbridge Gas Distribution will be kept whole with respect to income taxes over the full economic life of utility assets, including the 10-year life of the CIS assets. Parties disagree over when the tax savings should be reflected in revenue requirement and rates.

To support a settlement, the parties agree, for ratemaking purposes, to the use of the values included in Row 3 of the Template in determining the revenue requirement for use at True-Up Time. Those values are calculated as if the CIS costs, including tax savings, were calculated on a conventional forward test year cost of service basis for each year during the period 2009-2012. The Company has agreed to use this assumption on the understanding that Enbridge Gas Distribution retains the right to bring an application before the Board seeking a different approach to the timing of when the tax savings are reflected in revenue requirement. Enbridge Gas Distribution agrees that it will, if it elects to make such application, file that application by June 30, 2007. Intervenors' rights to oppose any such application remain unfettered and they retain the right to rely on any and all grounds of opposition considered by them to be appropriate. The parties agree that there will be no inference that Enbridge Gas Distribution has tacitly acquiesced to values in Row 3, by accepting them in this Supplementary Settlement Agreement, and all parties acknowledge that the Company's acceptance of the values in Row 3 is "without prejudice" to the application described above, should the Company decide to file it by June 30, 2007. In the event that the Board approves a different approach to the timing of when the tax savings are reflected in revenue requirement, then parties agree that the values shown in Row 3 of the Template are to be adjusted accordingly. If Enbridge Gas Distribution does not file such an application by June 30, 2007, or if Enbridge Gas Distribution files such an application but the relief requested is not granted, then, subject to the remaining possible adjustments described below, the values in Row 3 of the Template will remain as stated therein.

The two remaining potential adjustments to the CIS revenue requirement amounts for the period 2009 through 2012, as shown in Row 3 of the Template, pertain to Enbridge Gas Distribution's equity ratio and the possibility that the system integrator contract costs resulting from the CIS procurement process are less than $42 million.

The amounts in Row 3 of the Template reflect a 35% level of deemed equity for the Company. The issue of the appropriate level of deemed equity for the Company is currently before the Board in this F2007 rate case, and there may be changes from the 35% level. Parties agree that the amounts in Row 3 of the Template should be adjusted at True-Up Time in the event that the Company's level of deemed equity is changed in the Board's decision in the F2007 rate case.

The amounts in Row 3 of the Template reflect a $118.7 million cost for the new CIS. In the event that the system integrator contract costs arrived at through the CIS RFP process are less than $42 million, then parties agree that the amounts in Row 3 should be adjusted accordingly. In the event that the system integrator costs are $42 million or more, then the parties agree to the cost of $118.7 million for the term of this agreement.

Subject to the outcome of any application which Enbridge Gas Distribution may bring before the Board, as described above, Enbridge Gas Distribution agrees that once the outstanding items on the Template are determined, and completed, and as a result the Normalized 2008 Customer Care Revenue Requirement is established, the Company will not seek any adjustment to its rates or revenue requirement relating to the cost of the new CIS during the term of this agreement. Intervenors similarly agree that they will not seek adjustments to the Company's rates or revenue requirement that are directly or indirectly based on changes in CIS costs.

Notwithstanding the limitations expressed in the preceding paragraphs, the parties agree that in the event that new legislative or regulatory requirements, that are currently unknown and that are beyond the Company's control, are imposed on the Company, in the period up to and including 2012, and those requirements materially change the level of CIS costs, then any of the parties shall be entitled to make application to the Board for adjustments to rates or revenue requirement as appropriate. The materiality threshold that applies to this aspect of the agreement will be established at the IR proceeding. The parties agree that the rights conferred in this paragraph will be no greater than any rights to revisit any issue based on changes in legislative or regulatory requirements that are established as part of the IR rules that apply to the Company.

(v) Future revenue-generating opportunities from the new CIS

The Company agrees to use its best efforts to identify and take advantage of opportunities to use the new CIS asset to provide CIS services to third party organizations to generate additional revenue opportunities, and that the gains from any such opportunities shall be shared with ratepayers in a manner to be agreed upon. A consultative group, including Intervenors, may be convened to consider how such opportunities would be addressed. The parties agree that, in the event that the sharing of such gains cannot be agreed upon by the parties, then they will put the issue of the appropriate gainsharing to be used to the Board. The parties agree that any gains to be shared with ratepayers would be cleared to ratepayers by way of an annual adjustment to delivery rates.

Billing services on the Enbridge Gas Distribution bill are covered by the Supplementary Settlement Proposal related to open bill access (Ex. N1-1-1, Appendix C), and are not included in or affected by the provisions set out above.

APPENDIX A – TRUE-UP RULES

Attached to this Appendix A is a document entitled "Customer Care and CIS Settlement Template" (the "Template"). The parties have completed each of the boxes A1 through G17 of the Template, by inserting a dollar amount, or zero, or a TBD (To Be Determined) which will be completed at the True-Up Time. The following rules apply to the completion of the Template:

1) Where in the Template there is a dollar figure or zero already inserted in any box, that figure is agreed by the parties, and subject to paragraphs 3, 4 and 6 below, will not be altered.

2) The figures agreed to by the parties which are fixed and not subject to change, and which are already included in certain boxes within the Template, include the following:

    a. Rows 1, 2 and 2a: rows 1 and 2 represent the amounts that parties agree can be recovered in rates related to payments by Enbridge Gas Distribution to ABSU to provide CIS services and the payments by ABSU to ECSI for the use of the existing CIS asset, until the new CIS asset is in service. Row 2a represents the amounts to be paid to CWLP for the use of the CIS asset from January 1, 2007 to March 31, 2007. Parties agree that a total of $28.9 million shall be included on these rows, divided into the individual amounts included in the Template.

    b. Row 4: parties agree to the figures included in the Template as the amounts to be paid for the hosting and support of the new CIS. These amounts are based on Enbridge Gas Distribution estimates which the Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

    c. Row 5: parties agree to the figures included in the Template as the amounts to be recovered for the Company's backoffice costs (excluding bad debt) associated with both the old and the new CIS. These amounts are based on Enbridge Gas Distribution estimates which the Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

    d. Rows 6 and 7: SAP has been chosen as the provider for the software that will support the new CIS. This software may require some modifications or adaptations, from time to time, to fully support the CIS. The parties agree to the figures included rows 6 and 7 of the Template as the amounts to be paid to SAP for licence fees and for modifications that may be necessary. These amounts are based on Enbridge Gas Distribution estimates which the Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

e. Row 8: box 8A includes the amount of $16.9 million, which is the amount that parties have agreed can be recovered in rates related to the provision of Customer Care services by CWLP for the period from January 1, 2007 to March 31, 2007 (which is the date on which ABSU will begin providing Customer Care services on a temporary or permanent basis). Given that CWLP will stop providing services to Enbridge Gas Distribution as of April 2007, the amounts to be reflected in boxes 8B, 8C, 8D, 8E and 8F are zero.

f. Row 11: parties agree to the figures included in the Template as the amounts to be recovered for Customer Care licences to support the existing and new Customer Care service provider delivery of Collections, E-Billing and text to speech voice capability functions. These amounts are based on Enbridge Gas Distribution estimates which Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

g. Row 12: parties agree to the figures included in the Template as the amounts to be recovered for the Company's backoffice costs (excluding bad debt) associated with Customer Care services. These amounts are based on Enbridge Gas Distribution estimates which Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

h. Row 13: this row includes the costs incurred by the Company, and accepted for recovery from ratepayers, related to the procurement of a new customer care service provider. The parties have agreed that a total amount of $4.9 million may be recovered at row 13. This total amount represents the internal and external procurement costs for the new Customer Care services that have been determined by the parties to be prudently incurred and reasonable for recovery from ratepayers. This total amount is allocated equally over the five years from 2008 to 2012. Thus, the amount of $0.98 million is inserted in each of the boxes A13 to F13.

i. Row 17: the total number of customers for each year.

3) Row 3 includes the revenue requirement associated with the new CIS for each of the years from 2007 to 2012, to be filled in as follows:

a. The amounts in boxes A3 and B3 shall be zero, since there is no revenue requirement associated with the new CIS until 2009.

b. The amounts in boxes C3, D3, E3 and F3 represent the annual revenue requirement associated with each of 2009, 2010, 2011 and 2012 for the new CIS. These amounts, which total $46.210 million, are based upon the agreed-upon cost of the new CIS of $118.7 million. The derivation of these amounts is set out in the spreadsheets attached as Appendix B and the total of $46.210 million is the sum of the items in Columns 1, 2, 3 and 4 at line 12 on the first page of Appendix B. These amounts are subject to adjustment as follows:

   i. the amounts in row 3 of the Template reflect a $118.7 million cost for the new CIS. In the event that the system integrator contract costs arrived at through the CIS RFP process are less than $42 and the overall cost is therefore reduced, then parties agree that the amounts in row 3 should be changed to correspond to the lower new CIS cost;

   ii. the amounts in row 3 of the Template reflect a 35% level of deemed equity for the Company. The issue of the appropriate level of deemed equity for the Company is currently before the Board in this F2007 rate case, and there may be changes from the 35% level. Parties agree that the amounts in row 3 of the Template should be changed in the event that the Company's level of deemed equity is changed;

   iii. In the event that the Company is successful in an application to the Board for a different approach to the timing of when tax savings associated with the new CIS are reflected in revenue requirement, then corresponding changes will be made to the amounts in row 3.

4) The amounts to be inserted in boxes A9 and B9 shall be determined by the parties as the prudent and reasonable amounts for recovery from ratepayers for sums paid or forecast to be payable by the Company to ABSU for Customer Care services during the period April 1, 2007 through September 30, 2008, in accordance with the following criteria:

   a. In the event that ABSU is chosen as the new service provider for Customer Care services from and after April 1, 2007 until December 31, 2012, then the figures to be inserted in boxes A9 and B9 are zero, because there will be no need for a transition period to a new service provider;

b. In the event that a third party other than ABSU is chosen as the new service provider for Customer Care services, then there will be the need for a transition period, for a maximum of 18 months from April 1, 2007, during which ABSU will provide Customer Care services until the new service provider can be fully phased-in.

c. The Company has reached agreement with ABSU for Customer Care services to be provided, on a transition basis for 2007 and 2008 in the event that ABSU is not the successful Customer Care bidder. For settlement purposes, subject to subparagraph (d) below, the Parties agree that amounts of up to $52,263,000 for 2007 and $42,623,000 for 2008 will be included in boxes A9 and B9. These numbers represent the maximum agreed-upon level of costs that the Company may recover in rates in respect of the amounts charged by ABSU during 2007 and 2008 for Customer Care services, on a transitional basis, based on a recoverable cost of $38 per customer per year and a transition period of 18 months;

d. The Company will make best efforts to reduce the length of the transition period from 18 months, and to reduce the actual forecast costs per customer from ABSU to be less than currently forecast. In the event that the actual costs to date and updated forecast costs from ABSU at True-up Time for Customer Care services for the transition period are less than $52,263,000 for 2007 or $42,623,000 for 2008, then the numbers to be inserted in boxes A9 and B9 will be the actual costs to date and updated forecast costs at True-Up Time.

e. The amounts to be inserted in boxes C9, D9, E9 and F9 are zero because, in any event, the transition period for customer care services will not extend beyond 2008.

5) The amounts to be inserted in boxes A10 to F10 are the reasonable forecast annual costs of the new Customer Care service provider, to be determined at the True-Up Time through the results of the Customer Care procurement process. In the event that ABSU is chosen as the new service provider, it is expected that these amounts will be effective as of April 1, 2007. In the event that a third party other than ABSU is chosen as the new service provider, it is expected that these amounts will begin at some time in 2007 or 2008, because of the need for transition time and activities. The amounts to be included in these boxes are subject to review by the Consultative for prudence and reasonableness. In the event that the Intervenors and the Company do not agree, the issue of prudence and reasonableness will be determined by the Board.

6) The amounts at rows 14 and 15 represent the transition costs associated with moving from CWLP as the Customer Care service provider to a different third party service provider. The transition costs to be included in these rows, and tracked in the 2007 and 2008 Customer Care Transition Costs Variance Accounts, relate to activities that ABSU and external contractors and internal resources will undertake to transfer knowledge and services to the new service provider. This will include such tasks as training, documentation and management of the vendors through the transition.

   a. In any event, the number in boxes A14/A15 will be zero.

   b. In the event that ABSU is chosen as the new Customer Care service provider then the amounts to be inserted in boxes B14 to F14 and B15 to F15 are zero and subparagraphs 6(c) to (f) do not apply.

   c. In the event that a different third party is chosen as the new Customer Care service provider, then a total amount of $11.1 million will be included on rows 14 and 15. This total amount will be split equally between the years 2008 to 2012, in the amount of $2.22 million per year. Thus, each of boxes B14/B15, C14/C15, D14/D15, E14/E15 and F14/F15 will include the number $2.22 million.

   d. The Company will record all prudent and reasonable amounts spent for services, both internal and external, to facilitate the transition from CWLP/ABSU providing Customer Care services to a new service provider in the 2007 and 2008 Customer Care Transition Costs Variance Accounts, to a total maximum of $11.1 million. It is agreed that amounts paid for internal costs shall not include the costs of employees or other resources already included in the budget for the year and re-assigned to this transition, unless a specific new resource was acquired to backfill those other functions.

   e. Commencing in 2008, and continuing each year until 2012, the Company will expense the amount of $2.22 million for Customer Care costs, and will at the same time, deduct the same amount from the total amounts recorded in the 2007 and 2008 Customer Care Transition Costs Variance Accounts. The parties agree that, even if the outstanding balance in the 2007 and 2008 Customer Care Transition Costs Variance Accounts becomes zero before 2012, the Company is still entitled to expense and recover the amount of $2.22 million for each year until 2012. The parties further agree that no negative balances will be reflected in the 2007 and 2008 Customer Care Transition Costs Variance Accounts.

f. Parties agree that if the total amounts recorded in the 2007 and 2008 Customer Care Transition Costs Variance Accounts are less than $11.1 million as of December 31, 2008, then the difference between $11.1 million and the total amounts recorded in the 2007 and 2008 Customer Care Transition Costs Variance Accounts will be credited to ratepayers with interest in equal amounts in 2009 to 2012.

7) Row 16 will be the totals of each of the columns, to be completed when all of the above figures are determined.

8) Column G will be the totals of each of the rows, to be completed when all of the above figures are determined.

9) Box G16 will be the total of all Customer Care costs and revenue requirement forecast for the period (the "Total Customer Care Forecast").

10) Box G17, already completed, is the forecast total of annual numbers of customers during the period (the "Customer Count").

At True-Up Time, once the Template has been completed, then the Normalized 2007 Customer Care Revenue Requirement can be determined. This will be calculated by starting with the Total Customer Care Revenue Requirement for 2007 to 2012, which is the sum of boxes A16 to F16. That Total Customer Care Revenue Requirement will then be placed into an amortization model that calculates, using the IR annual adjustment that is approved for Enbridge Gas Distribution, the Normalized 2007 Customer Care Revenue Requirement which is the number that, when adjusted for IR annual adjustment for each year from 2008 through 2012, would allow the Company to fully recover the Adjusted Customer Care Revenue Requirement for 2007 to 2012.

At the same time, parties will calculate the 2007 Customer Care Revenue Requirement Variance by taking the difference between the Normalized 2007 Customer Care Revenue Requirement and the placeholder of $90.8 million. The Company will credit or debit the 2007 Customer Care Revenue Requirement Variance, as the case may be, to the 2007 Customer Care Variance Account. The balance in that account will be repaid to the ratepayers, or charged to the ratepayers, with interest, over the course of 2008 to 2012.

Attached to this Appendix A is an illustrative example of how the True-Up will be applied. For the purpose of this example, the following assumptions have been employed: (i) at row 3, the CIS cost is recovered by recognizing the tax shield benefit in the first four years, and a deemed equity level of 35% is assumed; (ii) ABSU is not awarded the Customer Care contract, so there are transition costs included at row 9; (iii) at row 10, the new CIS service provider contract cost is $60 million per year; and (iv) the

IR Annual Adjustment is 1%. The illustrative example sets out the steps that are followed, and the amortization model that is used, to derive the 2007 Customer Care Revenue Requirement Variance and the Normalized Customer Care Revenue Requirements for 2007 to 2012.

Customer Care and CIS Settlement Template

#	Category of Cost	A 2007	B 2008	C 2009	D 2010	E 2011	F 2012	G Totals
	CIS Related Categories							
1	*Old CIS Licence Fee*							
2	*Old CIS Hosting and Support*	$14,200,000	$9,800,000	$4,900,000	$0	$0	$0	$28,900,000
2a	*Incumbent (CWLP) CIS Services being provided from January to March 2007*							
3	*New CIS Capital Cost*	$0	$0	$880,000	($5,340,000)	$25,810,000	$24,860,000	$46,210,000
4	*New CIS Hosting and Support*	$0	$0	$4,350,000	$8,700,000	$8,700,000	$8,700,000	$30,450,000
5	*CIS Backoffice (EGD Staffing)*	$1,000,000	$1,030,000	$2,000,000	$2,060,000	$2,121,800	$2,185,454	$10,397,254
6	*SAP Licence Fees*	$0	$0	$1,113,500	$2,227,000	$2,227,000	$2,227,000	$7,794,500
7	*SAP Modifications*	$0	$0	$1,000,000	$1,000,000	$0	$0	$2,000,000
	Customer Care Related Categories							
8	*Incumbent (CWLP) Customer Care Services being provided from - January to March 2007*	$16,900,000	$0	$0	$0	$0	$0	$16,900,000
9	*Customer Care Transition Service Provider Contract Cost - ABSU April, 2007 to Sep 30, 2008*	Up to $52,263,000	Up to $42,623,000	$0	$0	$0	$0	$0
10	*New Service Provider Contract Cost*	TBD	TBD	TBD	TBD	TBD	TBD	$0
11	*Customer Care Licences*	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$8,400,000
12	*Customer Care Backoffice (EGD staffing)*	$3,100,000	$3,193,000	$3,288,790	$3,387,454	$3,489,077	$3,593,750	$20,052,071
13	*Customer Care Procurement Costs*	$0	$980,000	$980,000	$980,000	$980,000	$980,000	$4,900,000
14	*Transition Costs - Consultants and ISP*	$0	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$11,100,000
15	*Transition Costs - EGD Staffing*							
16	**Total CIS & Customer Care**	TBD	TBD	TBD	TBD	TBD	TBD	TBD
17	*Number of Customers*	1,831,283	1,878,004	1,925,563	1,973,575	2,021,588	2,069,600	11,699,613

Customer Care and CIS Settlement Template - Example for purpose of illustrating True-Up

#	Category of Cost	A 2007	B 2008	C 2009	D 2010	E 2011	F 2012	G Totals
	CIS Related Categories							
1	Old CIS Licence Fee							
2	Old CIS Hosting and Support	$14,200,000	$9,800,000	$4,900,000	$0	$0	$0	$28,900,000
2a	Incumbent (CWLP) CIS Services being provided from January to March 2007							
3	New CIS Capital Cost (Intervenor Model @ 35% Equity)	$0	$0	$880,000	($5,340,000)	$25,810,000	$24,860,000	$46,210,000
4	New CIS Hosting and Support	$0	$0	$4,350,000	$8,700,000	$8,700,000	$8,700,000	$30,450,000
5	CIS Backoffice (EGD Staffing)	$1,000,000	$1,030,000	$2,000,000	$2,060,000	$2,121,800	$2,185,454	$10,397,254
6	SAP Licence Fees	$0	$0	$1,113,500	$2,227,000	$2,227,000	$2,227,000	$7,794,500
7	SAP Modifications	$0	$0	$1,000,000	$1,000,000	$0	$0	$2,000,000
	Customer Care Related Categories							
8	Incumbent (CWLP) Customer Care Services being provided from - January to March 2007	$16,900,000	$0	$0	$0	$0	$0	$16,900,000
9	Customer Care Transition Service Provider Contract Cost - ABSU April, 2007 to Sep 30, 2008	$52,263,530	$42,623,220	$0	$0	$0	$0	$94,886,750
10	New Service Provider Contract Cost - (Values placed for illustrative purposes)	$0	$24,000,000	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$264,000,000
11	Customer Care Licences	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$8,400,000
12	Customer Care Backoffice (EGD staffing)	$3,100,000	$3,193,000	$3,288,790	$3,387,454	$3,489,077	$3,593,750	$20,052,071
13	Customer Care Procurement Costs	$0	$980,000	$980,000	$980,000	$980,000	$980,000	$4,900,000
14	Transition Costs - Consultants and ISP	$0	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$11,100,000
15	Transition Costs - EGD Staffing							
16	**Total CIS & Customer Care**	$88,863,530	$85,246,220	$82,132,290	$76,634,454	$106,947,877	$106,166,204	$545,990,575
17	Number of Customers	1,831,283	1,878,004	1,925,563	1,973,575	2,021,588	2,069,600	11,699,613

	True-Up Process Step	A	B	C	D	E	F	G
18	The Normalized 2007 Customer Care Revenue Requirement can be determined. This will be calculated by starting with the Total Customer Care Revenue Requirement for 2007 to 2012, which is the amount in box G16	$545,990,575						
19	That Total Customer Care Revenue Requirement will then be placed into an amortization model that calculates, using the IR annual adjustment that is approved for Enbridge Gas Distribution, the Normalized 2007 Customer Care Revenue Requirement which is the number that, when adjusted for IR annual adjustment for each year from 2008 through 2012, will allow the Company to fully recover the Total Customer Care Revenue Requirement for 2007 to 2012	$88,749,876.15						
20	The Normalized 2007 Customer Care Revenue Requirement will then be compared to the 2007 placeholder of $90.8 million, and the difference will be the 2007 Customer Care Revenue Requirement Variance.	($2,050,124)						
21	The Company will credit or debit the 2007 Customer Care Revenue Requirement Variance, as the case may be, to the 2007 Customer Care Variance Account. The balance in that account will be repaid to the ratepayers, or charged to the ratepayers, with interest, over the course of 2008 to 2012.		($410,025)	($410,025)	($410,025)	($410,025)	($410,025)	
22	The Normalized 2008 Customer Care Revenue Requirement will be the Normalized 2007 Customer Care Revenue Requirement, plus or minus the IR annual adjustment that is approved for Enbridge Gas Distribution.		$89,637,375	$90,533,749	$91,439,086	$92,353,477	$93,277,012	
23	Total Customer Care Revenue By Year (Including repayment of 2007 variance)	$ 90,800,000	$ 89,227,350	$ 90,123,724	$ 91,029,061	$ 91,943,452	$ 92,866,987	$ 545,990,575
24	Normalized Customer Care Revenue Requirement Per Customer without Bad Debt	$ 49.58	$ 47.51	$ 46.80	$ 46.12	$ 45.48	$ 44.87	
25	IR Annual Adjustment	1%						

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Capital Structure
65% Incremental Long Term Debt / 35% Equity

Line No.		Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component	Col. 4 (4 dec.) Return Component
		%	%	%	%
1.	Long-term debt	65.00	5.35	3.48	3.4775
2.	Short-term debt	0.00	0.00	0.00	0.0000
3.		65.00		3.48	3.4775
4.	Preference shares	0.00	0.00	0.00	0.0000
5.	Common equity	35.00	8.39	2.94	2.9365
6.		100.00		6.42	6.4140

	($Millions)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
7.	Ontario Utility Income ($M)	6.69	9.89	(10.77)	(10.92)	(11.07)	(11.22)	(11.37)	(11.52)	(11.67)	(11.81)
8.	Rate base ($M)	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
9.	Indicated rate of return %	5.921 %	9.783 %	(12.074)%	(14.125)%	(16.921)%	(20.963)%	(27.311)%	(38.734)%	(65.372)%	(198.101)%
10.	(Deficiency) in rate of return %	(0.493)%	3.369 %	(18.488)%	(20.539)%	(23.335)%	(27.377)%	(33.725)%	(45.148)%	(71.786)%	(204.515)%
11.	Net (deficiency) ($M)	(0.56)	3.41	(16.49)	(15.88)	(15.27)	(14.65)	(14.04)	(13.43)	(12.81)	(12.19)
12.	Gross (deficiency) ($M)	(0.88)	5.34	(25.81)	(24.86)	(23.90)	(22.93)	(21.98)	(21.02)	(20.05)	(19.08)

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Rate Base

($Millions)

Line No.		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Property, plant, and equipment										
1.	Cost or redetermined value	118.93	118.93	118.93	118.93	118.93	118.93	118.93	118.93	118.93	118.93
2.	Accumulated depreciation	(5.95)	(17.84)	(29.73)	(41.62)	(53.51)	(65.41)	(77.30)	(89.19)	(101.08)	(112.97)
3.	Net Property, plant, and equipment	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
	Allowance for working capital										
4.	Accounts receivable merchandise finance plan	-	-	-	-	-	-	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-	-	-	-	-	-	-
6.	Materials and supplies	-	-	-	-	-	-	-	-	-	-
7.	Mortgages receivable	-	-	-	-	-	-	-	-	-	-
8.	Customer security deposits	-	-	-	-	-	-	-	-	-	-
9.	Prepaid expenses	-	-	-	-	-	-	-	-	-	-
10.	Gas in storage	-	-	-	-	-	-	-	-	-	-
11.	Working cash allowance	-	-	-	-	-	-	-	-	-	-
12.		-	-	-	-	-	-	-	-	-	-
13.	Ontario utility rate base	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Income

($Millions)

Line No.		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Revenue										
1.	Gas sales	-	-	-	-	-	-	-	-	-	-
2.	Transportation of gas	-	-	-	-	-	-	-	-	-	-
3.	Transmission and compression	-	-	-	-	-	-	-	-	-	-
4.	Storage service	-	-	-	-	-	-	-	-	-	-
5.	Other operating revenue	-	-	-	-	-	-	-	-	-	-
6.	Interest and property rental	-	-	-	-	-	-	-	-	-	-
7.	Other income	-	-	-	-	-	-	-	-	-	-
8.	Total revenue	-	-	-	-	-	-	-	-	-	-
	Costs and expenses										
9.	CIS -selection procurement cost	5.10	-	-	-	-	-	-	-	-	-
10.	Operation and maintenance	-	-	-	-	-	-	-	-	-	-
11.	Depreciation and amortization	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
12.	Provincial capital taxes	0.16	-	-	-	-	-	-	-	-	-
13.	Total costs and expenses	17.15	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
14.	**Utility income before inc. taxes**	(17.15)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)
	Income taxes										
15.	Excluding interest shield	(22.42)	(20.51)	-	-	-	-	-	-	-	-
16.	Tax shield on interest expense	(1.42)	(1.27)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
17.	Total income taxes	(23.84)	(21.78)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
18.	**Ontario utility net income**	6.69	9.89	(10.77)	(10.92)	(11.07)	(11.22)	(11.37)	(11.52)	(11.67)	(11.81)

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Taxable Income and Income Tax Expense

($Millions)

Line No.		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1.	Utility income before income taxes	(17.15)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)
	Add Backs										
2.	Depreciation and amortization	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
3.	Large corporation tax	-	-	-	-	-	-	-	-	-	-
4.	Other non-deductible items	-	-	-	-	-	-	-	-	-	-
5.	Any other add back(s)	-	-	-	-	-	-	-	-	-	-
6.	Total added back	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
7.	Sub total - pre-tax income plus add backs	(5.26)	-	-	-	-	-	-	-	-	-
	Deductions										
8.	Capital cost allowance - Federal	56.80	56.80	-	-	-	-	-	-	-	-
9.	Capital cost allowance - Provincial	56.80	56.80	-	-	-	-	-	-	-	-
10.	Items capitalized for regulatory purposes	-	-	-	-	-	-	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-	-	-	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-	-	-	-	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-	-	-	-	-	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-	-	-	-	-	-	-
15.	Any other deduction(s)	-	-	-	-	-	-	-	-	-	-
16.	Total Deductions - Federal	56.80	56.80	-	-	-	-	-	-	-	-
17.	Total Deductions - Provincial	56.80	56.80	-	-	-	-	-	-	-	-
18.	Taxable income - Federal	(62.06)	(56.80)	-	-	-	-	-	-	-	-
19.	Taxable income - Provincial	(62.06)	(56.80)	-	-	-	-	-	-	-	-
20.	Income tax provision - Federal @ 22.12 %	(13.73)	(12.56)	-	-	-	-	-	-	-	-
21.	Income tax provision - Provincial @ 14.00 %	(8.69)	(7.95)	-	-	-	-	-	-	-	-
22.	Income tax provision - combined	(22.42)	(20.51)	-	-	-	-	-	-	-	-
23.	Part V1.1 tax	-	-	-	-	-	-	-	-	-	-
24.	Investment tax credit	-	-	-	-	-	-	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(22.42)	(20.51)	-	-	-	-	-	-	-	-
	Tax shield on interest expense										
26.	Rate base as adjusted	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
27.	Return component of debt	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%
28.	Interest expense	3.93	3.52	3.10	2.69	2.28	1.86	1.45	1.03	0.62	0.21
29.	Combined tax rate	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612
30.	Income tax credit	(1.42)	(1.27)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
31.	**Total income taxes**	(23.84)	(21.78)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Revenue Requirement

Line No.	**($Millions)**	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Cost of capital										
1.	Rate base	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
2.	Required rate of return	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%
3.	Cost of capital	7.25	6.48	5.72	4.96	4.20	3.43	2.67	1.91	1.15	0.38
	Cost of service										
4.	CIS -selection procurement cost	5.10	-	-	-	-	-	-	-	-	-
5.	Operation and maintenance	-	-	-	-	-	-	-	-	-	-
6.	Depreciation and amortization	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
7.	Municipal and other taxes	0.16	-	-	-	-	-	-	-	-	-
8.	Cost of service	17.15	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
	Misc. & Non-Op. Rev										
9.	Other operating revenue	-	-	-	-	-	-	-	-	-	-
10.	Other income	-	-	-	-	-	-	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-	-	-	-	-	-	-
	Income taxes on earnings										
12.	Excluding tax shield	(22.42)	(20.51)	-	-	-	-	-	-	-	-
13.	Tax shield provided by interest expens	(1.42)	(1.27)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
14.	Income taxes on earnings	(23.84)	(21.78)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
	Taxes on deficiency										
15.	Gross deficiency	(0.88)	5.34	(25.81)	(24.86)	(23.90)	(22.93)	(21.98)	(21.02)	(20.05)	(19.08)
16.	Net deficiency	(0.56)	3.41	(16.49)	(15.88)	(15.27)	(14.65)	(14.04)	(13.43)	(12.81)	(12.19)
17.	Taxes on deficiency	0.32	(1.93)	9.32	8.98	8.63	8.28	7.94	7.59	7.24	6.89
18.	**Revenue requirement**	0.88	(5.34)	25.81	24.86	23.90	22.93	21.98	21.02	20.06	19.08
	Revenue at existing Rates										
19.	Gas sales	-	-	-	-	-	-	-	-	-	-
20.	Transportation service	-	-	-	-	-	-	-	-	-	-
21.	Transmission, compression and storag	-	-	-	-	-	-	-	-	-	-
22.	Rounding adjustment	-	-	-	-	-	-	-	-	-	-
23.	Revenue at existing rates	-	-	-	-	-	-	-	-	-	-
24.	**Gross revenue deficiency**	(0.88)	5.34	(25.81)	(24.86)	(23.90)	(22.93)	(21.98)	(21.02)	(20.06)	(19.08)

APPENDIX C

ENBRIDGE GAS DISTRIBUTION INC.

2007 TEST YEAR

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0034

INTERIM ORDER DATED MARCH 26, 2007

JULY 5, 2007

Ontario Energy Board | Commission de l'Énergie de l'Ontario

Ontario

EB-2006-0034

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2007.

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Paul Vlahos
Member

Ken Quesnelle
Member

INTERIM RATE ORDER ARISING FROM 2007 TEST YEAR SETTLEMENT PROPOSAL (EB-2006-0034)

Enbridge Gas Distribution Inc. ("EGDI") filed an application dated August 25, 2006 with the Ontario Energy Board (the "Board") under the Section 36 of the *Ontario Energy Board Act*, requesting a rate increase effective January 1, 2007. The Board issued a Notice of Application dated September 7, 2006 and subsequently has issued seven procedural orders. The procedural orders provided for, among other things, the convening of a Settlement Conference and direction for the filing and hearing of any Settlement Proposal.

The Settlement Conference commenced on December 11, 2006 and a Settlement Proposal was filed with the Board on January 24, 2007. Parties to the Settlement indicated that there were ongoing consultations on certain unsettled issues and additional settled issues could be filed during the course of the proceeding. If additional issues were partly or completely settled, the parties would file a supplementary settlement agreement that would explain the settlements, and the financial incremental impacts of such settlements. The Board heard and, with clarifications made on the record, accepted the Settlement Proposal on January 29, 2006.

The Settlement indicated that the implementation of the settlement package of issues, comprised of issues 1.1 to 1.8, 2.1, 2.2, 3.2, 3.5, 3.7 to 3.9, 3.11 to 3.15 and 9.1, will result in a revenue deficiency of $29.9 million. The Settlement Proposal included the agreement by all parties that …

> … for rate implementation purposes only, the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. GEC's and Pollution Probe's agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result of Issue 3.2. Schools' agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result of Issue 9.1. (Ex.N1 Tab1 Schedule 1 p9 /filed January 24, 2007)

On February 23, 2007 EGDI filed a draft interim rate order, including supporting documentation, for the Board's approval. EGDI indicated that the draft order reflected the impacts of the 2007 Settlement Proposal dated January 24, 2007. EGDI proposed that intervenors wishing to comment on the draft should file their submissions by March 2, 2007. EGDI also indicated that it would file a draft rate order under docket number EB-2007-0049 on March 2, 2007 seeking approval of rates effective April 1, 2007 using the Board approved QRAM methodology. The rates approved in EB-2007-0049 would immediately supersede those included, as appendix A, in this rate order.

The draft interim order included the following elements:

- Interim rates designed to recover a 2007 Test Year Revenue Requirement of $3,098.557 million.

- Revenue Adjustment Rate Rider applicable to billed volumes during the period April 1, 2007 to December 31, 2007 to recover $5.074 million in revenue. $5.074 million is the amount EGDI would have recovered if the proposed interim rates had been implemented on January 1, 2007.

On March 2, 2007 TransCanada Energy Ltd. submitted a request for explanation and reasons regarding the increase in Rate 125. EGDI provided a response on March 9, 2007.

Under proceeding EB-2007-0049, the April 2007 QRAM application, the Industrial Gas Users Association ("IGUA") submitted their concerns about the rates proposed in that proceeding and indicated their objections in the event that they did not receive a satisfactory explanation for the increase in certain rates. TransAlta Cogeneration L.P. and TransAlta Energy Corp also filed a submission indicating their support of IGUA's position. The QRAM panel referred this and subsequent IGUA and EGDI correspondence to this proceeding for consideration. During Day 15 of the EB-2006-0034 oral proceeding, IGUA indicated that it no longer objected to the proposed rates.

Upon reviewing the filed materials, the Board finds it appropriate to proceed with an interim rate order, effective January 1, 2007 with implementation beginning April 1, 2007.

A final rate order will be issued by the Board subsequent to the issuance of the Board's 2007 Test Year Decision with Reasons.

The Board notes that the rates in this Order will be immediately superceded by the rates approved in the April 2007 QRAM Decision and Order (EB-2007-0049)

THE BOARD ORDERS THAT:

1. The 2007 Settlement Proposal, dated January 24, 2007, attached as Appendix "A" and Supporting Documentation, attached as Appendix "B" to this order, are accepted as the basis for the rates in this order.

2. Rate Rider E, attached as Appendix “C”, will apply as a rate adjustment to a consumer’s actual consumption for the period April 1, 2007 to December 31, 2007.

3. The rates in the Rate Handbook, attached as Appendix “D” to this interim order, are hereby approved effective January 1, 2007. These rates will be immediately superceded by the rates resulting from the April 2007 QRAM decision.

DATED at Toronto, March 26, 2007

ONTARIO ENERGY BOARD

Original signed by

Peter H. O’Dell
Assistant Board Secretary

APPENDIX "A"

TO INTERIM RATE ORDER

BOARD FILE NO. EB-2006-0034

DATED MARCH 26, 2007

SETTLEMENT PROPOSAL

JANUARY 24, 2007

TABLE OF CONTENTS

<u>ISSUE</u>	**<u>DESCRIPTION (& EVIDENTIARY REFERENCE)</u>**
2.3	Is the forecast of degree days appropriate? (C2-4-1)
2.4	Are the average use-per-customer forecasts for rate class 1 and rate class 6 appropriate? (C1-3-1 and C2-3-1)
2.5	Is the proposed 2007 contract gas volume and revenue forecast appropriate? (C1-3-1)
2.6	Is the proposed 2007 General Service gas volume and revenue forecast appropriate? (C1-3-1)
3	**OPERATING COST (Exhibit D)**
3.1	Is the proposed 2007 gas cost forecast including the calculation of the PGVA Reference Price appropriate? (D1-4-1, D1-4-2)
3.2	Is the overall level of the 2007 Operation and Maintenance Budget appropriate? (D1-2-1)
3.3	Is the Company's proposed fuel switching program appropriate?
3.4	Is the Company's proposed Energy Link Program appropriate?
3.5	Is the budget for Human Resources related costs appropriate? (D1-4-1)
3.6	Do the revisions to the Regulatory Cost Allocation Methodology (RCAM) meet the Board's directives in the 2006 decision?
3.7	Is the proposed level of corporate cost allocation for 2007 appropriate?
3.8	Is Company's forecast level of Regulatory and OEB related costs for 2007 appropriate?
3.9	Is Enbridge's decision to change to a December 31 taxation year-end , in 2007, appropriate? (D1-5-1)
3.10	Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives? (D1-4-3)
3.11	Is the proposal to change depreciation rates for 2007, as proposed in the depreciation study, and the impact on 2007 customer rates,

ISSUE	DESCRIPTION (& EVIDENTIARY REFERENCE)
	appropriate? (D1-13-1, D2-2-1)
3.12	Is the proposal for the establishment of 2007 Deferral and Variance Accounts appropriate? (D1-7-1)
3.13	Is the proposal for the disposition of existing Deferral and Variance Accounts appropriate? (D1-7-2)
3.14	Are the amounts proposed to be included in rates for capital and property taxes appropriate?
3.15	Is the amount proposed to be included in rates for income taxes, including the methodology, appropriate?
4	**COST OF CAPITAL (Exhibit E)**
4.1	What is the Return on Equity (ROE) for EGDI for the 2007 test year as calculated pursuant to the ROE Guidelines?
4.2	Are Enbridge's proposed costs for its debt and preference share components of its capital structure appropriate? (E1-2-1)
4.3	Is the proposal to change the equity component of the deemed capital structure from 35% to 38% appropriate? (E2-2-1)
5	**COST ALLOCATION (Exhibit G)**
5.1	Is the Applicant's cost allocation appropriate and is it based in its 2006 Board approved methodology? (G2-T1-S1)
5.2	Is the proposal to recover Demand Side Management costs in delivery charges, as opposed to load balancing charges, appropriate? (from G2-3-1 to G2-3-4)
6	**RATE DESIGN (Exhibit H)**
6.1	Is the proposal to introduce delivery demand charges for Rates 100 and 145 reasonable? (H1-1-1)
6.2	Is the proposal to allocate revenue requirement between the customer classes and annually adjust the monthly customer charges and variable charges to recover the revenue deficiency reasonable? (H1-1-1)

ISSUE DESCRIPTION (& EVIDENTIARY REFERENCE)

6.3 Should the Board approve the contents of the Applicant's Rate Handbook? (H1-1-1, H2-6-1; A1-14-2)

6.4 Is the proposed treatment of bundled transportation charges and T-service credit appropriate in light of the Board's Decision in RP-2003-0203 and the settlement agreement? (H1-1-1)

7 CUSTOMER CARE SUPPORT, CUSTOMER CARE SYSTEM, AND OPEN BILL ACCESS

7.1 Has Enbridge complied with the direction, in the EB-2005-0001 Decision, to file in evidence the following Customer Care Support Cost information: all agreements between Enbridge and CWLP, ECSI or any other EI-related entity related to the provision of customer care or CIS; the Program Agreement between CWLP and Accenture, including any amendments or revisions; financial statements for ECSI and CWLP (historical, bridge and test year); the return analyses described in the decision? (D1-12-3)

7.2 What actions or decisions are required by the Board regarding items in the 2006 and 2007 capital budgets which might be duplicated in the upcoming application for a Regulatory Asset Account? (D1-10-1, p. 2/AppA)

7.3 Are the forecast costs of the new CIS system appropriate? (B1-5-1, p. 3)

7.4 What are the appropriate costs for CIS and Customer Care for 2007, including internal and transition costs? (D1-12-1, p. 2 and D3-2-1, p. 1)

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP 2005-0001? (D1-11-1 to 5)

8 OTHER ISSUES

8.1 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the NGEIR (EB-2005-0551) proceeding will be appropriately captured and reflected in this proceeding?

8.2 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the DSM

ISSUE	DESCRIPTION (& EVIDENTIARY REFERENCE)
	(EB-2006-0021) proceeding will be appropriately captured and reflected in this proceeding?
9	**RATE IMPLEMENTATION**
9.1	How should the Board deal with any revenue deficiency applicable from January 1, 2007 to the date that the Board's decision is implemented?
9.2	Should the Board set interim rates, effective January 1, 2007, to allow Enbridge to begin to recover its prospective revenue deficiency?

ATTACHMENTS

Appendix A- Deferral and Variance Accounts Balances

Appendix B- Approximations of rate impacts of the Settlement Proposal

PREAMBLE

This Settlement Proposal is filed with the Ontario Energy Board ("OEB" or "Board") in connection with the application of Enbridge Gas Distribution Inc. ("Enbridge Gas Distribution" or the "Company"), for an order or orders approving or fixing rates for the sale, distribution, transmission, and storage of gas for its 2007 fiscal year (the "Test Year").[1] A Settlement Conference was held between December 11, 2006 and January 5, 2007 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* (the "Rules") and the Board's *Settlement Conference Guidelines* ("Settlement Guidelines"). Ken Rosenberg acted as facilitator for the Settlement Conference. Settlement discussions between parties continued after that time. This Settlement Proposal arises from the Settlement Conference and subsequent discussions.

Enbridge Gas Distribution and the following intervenors (collectively, the "parties"), as well as Ontario Energy Board technical staff ("Board Staff"), participated in the Settlement Conference:

CONSUMERS COUNCIL OF CANADA (CCC)
DIRECT ENERGY MARKETING LIMITED (Direct Energy)
ENERGY PROBE RESEARCH FOUNDATION (Energy Probe)
GREEN ENERGY COALITION (GEC)
HVAC COALITION INC. (HVAC)
INDUSTRIAL GAS USERS ASSOCIATION (IGUA)
ONTARIO ASSOCIATION OF PHYSICAL PLANT ADMINISTRATORS (OAPPA)
ONTARIO ENERGY SAVINGS L.P. (OESLP)
POLLUTION PROBE
SCHOOL ENERGY COALITION (Schools)
SUPERIOR ENERGY MANAGEMENT (a division of Superior Plus Inc.) (Superior)
TRANSALTA COGENERATION L.P. AND TRANSALTA ENERGY CORP. (TransAlta)
TRANSCANADA PIPELINES LIMITED (TransCanada)
UNION ENERGY LIMITED PARTNERSHIP (Union Energy)
UNION GAS LIMITED (Union)
VULNERABLE ENERGY CONSUMERS COALITION (VECC)

The Settlement Proposal deals with all of the issues listed at Appendix "A" to the Board's Procedural Order #2, dated October 20, 2006 (the "Issues List"). The numbers ascribed to each of the issues correlate to the section numbers in the Settlement Proposal and each issue falls within one of the following three categories:

1. ***complete settlement*** **–** if the Settlement Proposal is accepted by the Board, the issue will not be addressed at the hearing because Enbridge

[1] In this Settlement Proposal, the terms "2007 fiscal year", "fiscal 2007" and "Test Year" each refer to the twelve-month period commencing January 1, 2007 and ending December 31, 2007.

Gas Distribution and all other parties who take any position on the issue agree to the proposed settlement;

2. ***incomplete settlement* –** if the Settlement Proposal is accepted by the Board, portions of the issue will be addressed at the hearing because parties are only able to agree on some, but not all, aspects of the issue; and,

3. ***no settlement* –** the issue will be addressed at the hearing because the parties who participated in the negotiation of the issue are unable to reach a settlement on the issue.

More particularly, the Settlement Proposal depicts the 47 issues enumerated on the Issues List as follows:

Complete Settlement Parties will not address the issue at the hearing	**Incomplete Settlement** Parties will address one or more parts of the issue at the hearing	**No Settlement** Parties will address the issue at the hearing
25 issues completely settled Issues 1.1, 1.3 to 1.8, 2.1, 2.2, 3.1, 3.5, 3.7 to 3.9, 3.11, 3.14, 3.15, 4.1, 5.1, 5.2, 6.1, 6.4, 8.1, 8.2 and 9.2	7 issues partly settled Issues 1.2, 3.2, 3.12, 3.13, 6.2, 6.3 and 9.1	15 issues not settled Issues 2.3 to 2.6, 3.3, 3.4, 3.6, 3.10, 4.2, 4.3 and 7.1 to 7.5

Issue 3.2, which relates to the Company's O&M Budget for the Test Year is an incomplete settlement, however, it should be noted that GEC and Pollution Probe object to the settled portions of this issue. Issue 9.1, which relates to rate implementation, is an incomplete settlement, however, it should be noted that Schools objects to the settled portions of this issue.

The description of each issue assumes that all parties participated in the negotiation of the issue, unless specifically noted otherwise. Any parties that are identified as not having participated in the negotiations of the issue also take no position on any settlement or other wording pertaining to the issue. Board Staff participated in the Settlement Conference, and has advised the parties that it does not oppose the proposed settlement on any of the completely settled or partly settled issues. However, in accordance with the Rules and the Settlement Guidelines, Board Staff takes no position on any issue and, as a result, is not a party to the Settlement Proposal.

The Settlement Proposal describes the agreements reached on the completely settled and partially settled issues. The Settlement Proposal identifies the parties who agree and who disagree with each settlement, or alternatively who take no position on the issue. Finally, the Settlement Proposal provides a direct link between each settled issue and the supporting evidence in the record to date. In this regard, the parties who agree with the individual settlements are of the view that the evidence provided is sufficient to support the Settlement Proposal in relation to the settled issues and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings agreeing with the proposed resolution of the settled issues. In the event that the Board does not accept the proposed settlement of any issue, further evidence may be required on the issue for the Board to consider it fully.

Best efforts have been made to identify all of the evidence that relates to each settled issue. The supporting evidence for each settled issue is identified individually by reference to its exhibit number in an abbreviated format; for example, Exhibit A1, Tab 8, Schedule 1 is referred to as A1-8-1. A concise description of the content of each exhibit is also provided. In this regard, Enbridge Gas Distribution's response to an interrogatory is described by citing the name of the party and the number of the interrogatory (e.g., Board Staff Interrogatory #1). The identification and listing of the evidence that relates to each settled issue is provided to assist the Board. The identification and listing of the evidence that relates to each settled issue is not intended to limit any party who wishes to assert that other evidence is relevant to a particular settled issue.

The parties agree that all positions, information, documents, negotiations and discussion of any kind whatsoever which took place or were exchanged during the Settlement Conference are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Settlement Proposal.

According to the Settlement Guidelines (p. 3), the parties must consider whether a settlement proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. Enbridge Gas Distribution and the other parties who participated in the Settlement Conference consider that no settled issue requires an adjustment mechanism other than those expressly set forth herein.

Issues 1.1 to 1.8, 2.1, 2.2, 3.2, 3.5, 3.7 to 3.9, 3.11 to 3.15 and 9.1 have been settled by parties as a package (the “package”), subject to the objections of GEC, Pollution Probe and Schools, as noted earlier, and none of the parts of this package are severable. All parties agree that, for rate implementation purposes only, the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company’s April 1, 2007 QRAM is implemented. GEC’s and Pollution Probe’s agreement in this regard is subject to any later adjustments to the Company’s recovery of revenue deficiency that might be required as a result of

Issue 3.2. Schools' agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result of Issue 9.1. Subject to considering the objections of GEC, Pollution Probe and Schools during the hearing, if the Board does not, prior to the commencement of the hearing of the evidence in EB-2006-0034, accept the package in its entirety, then there is no Settlement Proposal (unless the parties agree that any portion of the package that the Board does accept may continue as part of a valid Settlement Proposal). None of the parties can withdraw from the Settlement Proposal except in accordance with Rule 32 of the Rules. Finally, unless stated otherwise, the settlement of any particular issue in this proceeding is without prejudice to the rights of parties to raise the same issue in any future proceeding.

OVERVIEW

In order to address certain issues that have continued to be the subject of debate and discussion over a number of years, and in order to satisfy Board directions from the Decision with Reasons in the EB-2005-0001 case (the 2006 rate case), during the past year the Company has entered into a number of consultative processes with stakeholders. These consultatives were convened in respect of EnVision (issues 1.5 and 1.6), Corporate Cost Allocation (issues 3.6 and 3.7), customer care and CIS (issues 3.2 and 7.1 to 7.4) and open bill access (issue 7.5). These consultative processes have contributed greatly to the ability of all parties to come to settlements on many of these issues, as set out below. Several of the consultative processes are ongoing and may lead to settlement of additional issues. If additional issues are partly or completely settled, parties propose to file a supplementary settlement agreement that would explain the settlements, and the incremental financial impacts of such settlements.

Parties have been able to agree upon the package, which includes settlement of many of the issues raised in this proceeding. While some issues remain outstanding and unresolved, the impact of this Settlement Proposal, if accepted, is that the scope and length of the proceeding will be substantially reduced.

The Company's Application sought recovery of a revenue deficiency of $167.8 million. This figure was updated to $158.7 million in Impact Statement No. 1, to account for, among other things, the ROE for the Test Year of 8.39%.

Parties have agreed upon the settlement package of issues that, if accepted, would
reduce the revenue deficiency by $76.7 million. This would result in a remaining revenue /c
deficiency of $82.0 million. /c

The implementation of the settlement package of issues will result in a revenue deficiency
of $29.9 million, based on the Company's filing which expresses the revenue deficiency /c
as being relative to the Board-approved rates for F2006, and all of the items that make up

and contribute to those rates including, for example, the agreed-upon level of degree days for F2006.

The issues that are not settled by the Settlement Proposal represent an additional revenue deficiency amount of $52.1 million, based on the Company's filing, which will /c
require determination by the Board in the hearing. Based on positions that may be taken by parties in the hearing, the potential outcomes arising from the determination of these unsettled issues by the Board range from an incremental revenue sufficiency of approximately $5 million to an incremental revenue deficiency of $52.1 million. /c

Some intervenors assert that, if they are successful on outstanding issues (in particular issues related to Issue 2.2 regarding degree days), then there could be a revenue sufficiency in respect of those issues. Parties are able to agree, however, that for rate implementation purposes only, the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. This amount of $26.0 million will be subtracted from the total revenue deficiency resulting from the Board's final decision in this proceeding (which will include all impacts of this Settlement Proposal). The resulting revenue deficiency (or sufficiency) will be reflected and recovered in rates by the Company, subject to the outcome of Issue 9.1.

When implemented, the recovery of an additional $26.0 million will result in average increases, on an annual basis, of approximately 2% for Rate 1 customers, 1% for Rate 6 customers and between 0% and 2% increases for other rate classes. These average rate increases are relative to the July 1, 2006 QRAM rate and are calculated for a T-service customer, excluding commodity costs, and do not include impacts from the phase-in of cost allocation changes on October 1, 2006 and October 1, 2007. When these rate impacts are compared to the January 1, 2007 QRAM rate, the results are virtually identical as shown in Appendix B. The phase-in of cost allocation changes on October 1, 2007 will reduce the amounts recovered from Rate 1 and Rate 6 by approximately $5.01 million and $4.8 million respectively, and increase the amounts recovered from Rate 115, Rate 135 and Rate 170 by about $5.97 million, $0.6 million and $3.2 million respectively, as shown in Appendix B. The determination by the Board of the issues that are not settled will have additional rate impacts.

Attached as Appendix B is an approximation of the annual T-service rate increases that would result from the recovery of additional amounts of $26.0 million (the immediate additional amount to be recovered if the Settlement Proposal is accepted) and $82.0 /c
million (the maximum recoverable revenue deficiency if the Settlement Proposal is accepted and the Board decides the unsettled issues by adopting the Company's position on these issues). These approximations do not take account of the clearance of deferral and variance accounts, the phase-in of cost allocation changes or any allocation changes that might result from the resolution of Issue 6.2. These average annual T-service rate impact estimates are not indicative of the percentage T-service rate increase that will

occur on April 1, 2007, compared to T-service rates in force on March 31, 2007. T-service rate increases effective April 1, 2007 will include the rate increase associated with the nine month Rate Rider described in Issue 9.1. The Company believes, based on the analysis that it has undertaken, that these approximations of average annual T-service rate impacts, which are expressed relative to the July 1, 2006 QRAM rates and the January 1, 2007 QRAM rates, and are calculated for a T-service customer excluding commodity costs, are correct within +/- 0.5%.

1 RATE BASE (Exhibit B)

1.1 Are the amounts proposed for the 2007 Rate Base appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties have reached a global settlement of all 2007 Rate Base issues, except for issues related to the capital budget for the new CIS system. Issues related to the new CIS system are discussed below at Issues 7.2 to 7.4. The capital spending for the new CIS system will have no rate base impact in 2007. Parties agree that the Company will reduce the revenue deficiency associated with 2007 Rate Base issues by a total of $8 million, as compared to the Company's filed evidence. This will result in a 2007 capital budget of approximately $300 million, plus the cost of the Portlands Energy Centre Leave to Construct project, which is estimated at $18 million during the Test Year. The Portlands Energy Centre project, if approved in the leave to construct application, will not affect rates for the Test Year. Parties believe that the Board's consideration of the Portlands Energy Centre in the leave to construct application should be consistent with the principles set out under Issue 1.4 below.

Parties agree that the 2007 capital budget is an envelope amount, and the Company will have discretion to determine which items will be removed or changed from the Company's filed capital budget in order to reduce the overall level of that budget. Notwithstanding this discretion, the Company agrees that it will not proceed with the Automatic Meter Reading (AMR) project. Intervenors do not necessarily accept, and presently take no position on, the Company's decisions as to how it will allocate and spend the 2007 capital budget. Parties agree that, assuming the incentive regulation rate setting process allows for it, a normal review of the Company's capital spending in the Test Year may be undertaken as part of the rate setting process for 2008. The issue of capital spending on the EnergyLink program, included in Issue 3.4, is not settled, but the Board's decision on that issue will not affect the overall capital budget for the Test Year, only the Company's ability to allocate funds to EnergyLink within that budget. Parties accept the Company's opening rate base for 2007.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-1-1	Utility Rate Base
B1-1-2	Utility Rate Base Year to Year Summary
B1-2-1	Rate Base Capital Budget
B3-1-1	Ontario Utility Rate Base – Comparison of 2007 Test Year to 2006 Bridge Year
B3-1-2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2007 Test Year
B3-1-3	Working Capital Summary of Average of Monthly Averages 2007 Test Year
B3-2-1	Utility Capital Expenditures Comparison Budget 2007 and Estimated 2006
B3-2-2	2007 Capital Expenditures by Project (Projects Exceeding $500,000)
B3-2-3	Gross Customer Additions and Average Cost per Customer Addition Budget 2007 and Estimated 2006
B3-2-4	System Expansion Portfolio – 2007
F3-1-3	Utility Rate Base 2007 Test Year
I-1-1 to 3	Board Staff Interrogatories 1 to 3
I-9-4 and 7	IGUA Interrogatories 4 and 7
I-16-1 to 3	SEC Interrogatories 1 to 3
I-24-5 to 7	VECC Interrogatories 5 to 7
L-9-1	Evidence of IGUA
M1-1-1	Impact Statement #1

1.2 Are the amounts proposed for Capital Expenditures in 2007 appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

See Issue 1.1.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-2-1	Rate Base Capital Budget
B1-2-2	Details of Capital Expenditure and Justification for Major Capital Projects over $500,000
B1-3-1	Safety & Integrity Initiatives
B1-3-2	Leave to Construct Projects
B1-4-1	Information Technology Capital Budget
B1-5-1	CIS Project
B1-6-1	EnVision Project
B1-7-1	Automated Meter Reading (AMR)
I-1-4 to 6	Board Staff Interrogatories 4 to 6
I-2-1 to 4	CCC Interrogatories 1 to 4
I-9-2 and 5 to 6	IGUA Interrogatories 2 and 5 to 6

I-16-4 to 10	SEC Interrogatories 4 to 10
I-24-8 to 12	VECC Interrogatories 8 to 12

1.3 Is the budget amount proposed in 2007 for Safety & Integrity projects appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

See Issue 1.1. The Company will determine the 2007 capital expenditures budget for Safety and Integrity projects within the envelope set out under Issue 1.1.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-3-1	Safety & Integrity Initiatives
I-1-7	Board Staff Interrogatory 7
I-2-5 to 7	CCC Interrogatories 5 to 7
I-9-8	IGUA Interrogatory 8
I-16-11 to 12	SEC Interrogatories 11 to 12
I-24-13	VEC Interrogatory 13

1.4 How should the Board deal with the Leave to Construct ("LTC") projects included in the 2007 capital budget given that there will be separate Board Proceedings for the LTC projects?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties are of the view that the Board's decisions determining the appropriate total amount of capital spending by the Company in any test period are most suitably made in a rate application. In general, parties agree that the Board's decision with respect to overall capital spending does not imply specific approval of any individual leave to construct projects ("LTC Projects"), nor a decision as to the economic feasibility of any individual LTC Project. Similarly, parties agree that, generally, a decision with respect to the economic feasibility of an individual LTC

Project does not, in and of itself, imply that it is appropriate to include capital spending pertaining to that LTC Project in the capital budget for a test year used by the Board to establish rates.

In the context of the foregoing, the parties agree that the Board should deal with LTC Projects included in any test year capital budget as follows:

1. The total capital expenditures budget for a particular test year, to be considered and approved in a rate application, should include some evidence on individual LTC Projects planned for that year. However, the Board should not be asked to approve individual LTC Projects in a rate case. In a rate case, evidence with respect to individual LTC Projects need not be as extensive as the evidence required to support a LTC Application.

2. The economic feasibility of an individual project is considered in a leave to construct application. A LTC Application should not result in any adjustment to the Company's capital expenditures budget aside from exceptional circumstances, and in those cases the Board should consider and make the adjustment expressly.

3. A LTC Application can be heard by the Board prior to its consideration of the capital budget consequences of the LTC Project in a rates proceeding. In the event the Board approves a LTC Application, it will not be necessary to examine the justification for the LTC Project in a subsequent rate proceeding although the issue of the appropriate size of the overall capital budget would remain in issue in that hearing, and the leave to construct approval could inform that decision.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-3-2	Leave to Construct Projects
I-1-8 to 9	Board Staff Interrogatories 8 to 9
I-2-8	CCC Interrogatory 8
I-9-9	IGUA Interrogatory 9
I-16-13 to 14	SEC Interrogatories 13 to 14
I-19-4	TransAlta Interrogatory 4

1.5 Has the Company met the requirements of the Board's directive from the 2006 rate case to file an independent cost benchmark study for the EnVision project?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties agree that the Company has met the requirements of the Board's directive from the EB-2005-0001 Decision with Reasons by filing an independent cost benchmark study for the EnVision project.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B2-2-1	Compass Report – Envision Cost Benchmark Analysis
B1-6-1	EnVision Project

1.6 What are the appropriate EnVision cost and benefits and how should they be reflected in 2007 rates?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties agree that Compass carried out an appropriate cost benchmark study of the EnVision Project. Parties differ on how that benchmark should be applied in determining the costs and benefits associated with EnVision that should be reflected in rates. In order to resolve the EnVision issues in this proceeding, the Company has agreed to reduce the revenue requirement by $500,000 through a reduction in the 2007 Other O&M budget. This reduction is reflected and included in the $181.5 million total Other O&M budget agreed to below at Issue 3.2. The Company will continue to report annually to stakeholders on the achievement of EnVision benefits in the form and the manner set out in Tables 1 and 2 in Exhibit B1/T6/S1/pp 8-9. Parties agree that unless there is a change in the overall NPV of the EnVision project, there will be no need to revisit the EnVision project in future regulatory proceedings.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B2-2-1	Compass Report – Envision Cost Benchmark Analysis
B1-6-1	EnVision Project
1-2-9 to 17	CCC Interrogatories 9 to 17
1-16-15	SEC Interrogatory 15

1.7 Is the business case, including the total project amount of $133 million, proposed for the Automatic Meter Reading project ("AMR") justified?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

As part of the global settlement of 2007 rate base issues, the Company agrees not to proceed with the AMR project.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-7-1	Automated Meter Reading (AMR)
I-1-10 to 13	Board Staff Interrogatories 10 to 13
I-2-18 to 22	CCC Interrogatories 18 to 22
I-9-11	IGUA Interrogatory 11
I-16-16	SEC Interrogatory 16
I-24-14	VECC Interrogatory 14

1.8 Is the proposed recovery of AMR costs in 2007 rates appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

As part of the global settlement of 2007 rate base issues, the Company agrees not to proceed with the AMR project. As a result, this issue is no longer relevant.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-7-1	Automated Meter Reading (AMR)
1-24-15 to 16	VECC Interrogatories 15 to 16

2 OPERATING REVENUE (Exhibit C)

2.1 Is the proposed amount for 2007 Transactional Services revenue appropriate, and is the associated sharing mechanism in accordance with the 2006 decision?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties agree that the Company will share net transactional services revenues with ratepayers on a 75:25 basis in favour of ratepayers for transportation-related transactional services and on a 90:10 basis in favour of ratepayers for storage-related transactional services. The Company agrees to credit $8 million in transactional services revenue to ratepayers, to be credited to the revenue requirement for the purpose of setting rates for the Test Year. This credit will not be allocated as between transportation and storage transactional services. The 2007 Transactional Services Deferral Account will include the total of the ratepayers' shares of the net transactional services revenue for transportation-related and for storage-related transactional services, less the $8 million credit and the O&M costs associated with storage-related transactional services (estimated at $.1 million in the Company's updated evidence at Ex. C1-4-2). For greater certainty, if the result of these calculations is that the year-end balance in the 2007

Transactional Services Deferral Account would be less than zero, the balance shall be deemed to be zero.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-4-1	Transactional Services Revenue
C1-4-2	Transactional Services – Supplementary Evidence
I-1-14 to 15	Board Staff Interrogatories 14 to 15
I-2-23	CCC Interrogatory 23
I-9-13	IGUA Interrogatory 13
1-16-17	SEC Interrogatory 17
I-24-17 to 18	VECC Interrogatory 17 to 18
M1-1-1	Impact Statement #1

2.2 Is the proposed total 2007 Other Revenue Forecast appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties agree to increase the forecast for Other Operating Revenue for the Test Year from $23.7 million to $28.9 million, inclusive of the $3.5 million incremental impact of the resolution of the Transactional Services issue (described above at Issue 2.1), an increase of $1.0 million from the forecast of Other Service Revenues in the Company's evidence and the imputation of revenue of $700,000 for the Natural Gas Vehicles (NGV) program for the Test Year (in order to reflect the revenue deficiency of the NGV program).

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-5-1	Other Service and Late Payment Penalty Revenues
C3-5-1	Rate of Return on Capital Employed in the Natural Gas Vehicles Program

I-1-16	Board Staff Interrogatory 16
I-2-24 to 25	CCC Interrogatories 24 and 25
I-16-18	SEC Interrogatory 18
I-24-19 to 22	VECC Interrogatories 19 to 22
M1-1-1	Impact Statement No. 1
M1-2-5	Change in Revenue Requirement

2.3 Is the forecast of degree days appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C2-4-1	Budget Degree Days
I-1-17	Board Staff Interrogatory 17
I-9-3 and 14	IGUA Interrogatories 3 and 14
1-5-1 to 12	Energy Probe Interrogatories 1 to 12
1-16-19 to 20	SEC Interrogatories 19 to 20
L-9-1	Evidence of IGUA

2.4 Are the average use-per-customer forecasts for rate class 1 and rate class 6 appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Volume Budget
C2-3-1	Average Rate Use 1
C2-3-2	Average Use Rate 6
I-1-18	Board Staff Interrogatory 18
I-2-26 to 28	CCC Interrogatories 26 to 28
I-16-21 to 23	SEC Interrogatories 21 to 23
I-24-22 to 25	VECC Interrogatories 22 to 25

2.5 Is the proposed 2007 contract gas volume and revenue forecast appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Volume Budget
I-1-19	Board Staff Interrogatory 19
I-1-12	IGUA Interrogatory 12

2.6 Is the proposed 2007 General Service gas volume and revenue forecast appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Volume Budget
C1-1-1	Operating Revenue Summary
C1-2-1	Revenue Forecast
C3-1-1	Utility Operating Revenue 2007 Test Year
C3-1-2	Comparison of Utility Operating Revenue Budget 2007 and Estimate 2006
I-1-20	Board Staff Interrogatory 20
1-24-23 to 25	VECC Interrogatories 23 to 25

3 OPERATING COST (Exhibit D)

3.1 Is the proposed 2007 gas cost forecast including the calculation of the PGVA Reference Price appropriate?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Parties accept the Company's forecast of the cost consequences of the gas supply portfolio for the Test Year.

The Company agrees with certain parties that, when the issues list for the Natural Gas Forum proceeding about QRAM methodology is discussed, the Company will support the inclusion of an issue regarding the detailed calculation of the PGVA Reference Price.

Participating Parties: All parties participated in the negotiation and settlement of this issue except GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-4-1	Cost of Gas, Transportation and Storage
D1-4-2	Status of Contracts
D3-3-1	Summary of Gas Cost to Operations
D3-3-2	Summary of Gas Storage and Transportation Costs Fiscal 2007
D3-3-3	Canadian Peak Day Supply Mix
D3-3-4	Monthly Pricing Information
D3-3-5	Gas Supply/Demand
I-1-21	Board Staff Interrogatory 21
I-2-29	CCC Interrogatory 29
I-5-16 to 17	Energy Probe Interrogatory 16 to 17
I-9-16	IGUA Interrogatory 16
I-18-6	Superior Interrogatory 6
I-21-1 to 9	TransCanada Interrogatories 1 to 9
I-24-26	VECC Interrogatory 26

3.2 Is the overall level of the 2007 Operation and Maintenance Budget appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

The Company's overall Operations and Maintenance (O&M) budget, as filed in Impact Statement No. 1, for the Test Year totalled $365.8 million and can be divided into a number of categories: (i) customer care expenses (including CIS, internal costs and provision for uncollectibles) – filed as $120.1 million; (ii) corporate cost allocations – filed as $22.9 million; (iii) demand side management (DSM) programs – filed as $22.0 million; and (iv) Other O&M – filed as $200.8 million. The Company has also included transition costs of $10 million related to customer care as a separate line item in its filing.

Issues related the Company's customer care O&M budget (including the transition costs) are discussed below at Issues 7.1 to 7.4. Parties, except for GEC and Pollution Probe, agree on the balance of the Company's O&M budget for the Test Year.

Parties acknowledge that the Company's O&M DSM budget for the Test Year shall be $22.0 million, as set out in the Board's Decision with Reasons in EB-2006-0021 (the DSM generic hearing).

Parties agree that the Company's O&M budget for corporate cost allocations for the Test Year shall be $18.1 million. Parties agree to the overall level of this budget, but there is no specific agreement as to the amounts of each of the individual allocations. The issues about the corporate cost allocation methodology set out in Issue 3.6 remain unsettled.

Parties, except for GEC and Pollution Probe, agree that the Company's Other O&M budget for the Test Year, filed as $200.8 million, shall be reduced by $19.3 million to $181.5 million. Subject to the comments below, parties agree that the amount of the Other O&M budget is an envelope amount and the Company will have discretion to determine which items will be removed or changed from the Company's Other O&M budget as filed in order to reduce the overall level of that budget. Intervenors do not necessarily accept, and presently take no position on, the Company's decisions as to how it will allocate and spend the 2007 Other O&M budget.

Notwithstanding the agreement on the overall level of the Company's Other O&M budget for the Test Year, parties agree that certain components of the Company's Opportunity Development planned activities for the Test Year, specifically marketing activities, fuel switching and EnergyLink, will be examined before the Board. Parties, except for GEC and Pollution Probe, agree that the examination of those sub-issues before the Board will not impact on the $181.5 million agreed-upon level of the Other O&M budget for the Test Year. Subject to the exception set out below, parties other than GEC and Pollution Probe agree that they will not take any position in this proceeding on how the Company ought to allocate the agreed-upon $181.5 million Other O&M budget. Notwithstanding the foregoing, in the event that the Board determines that the Company may not proceed with EnergyLink, it is understood that Schools and/or HVAC may advance arguments about how the Company ought to spend the O&M amounts totaling $1.3 million (Ex. I-26-4) that were otherwise budgeted for EnergyLink. Notwithstanding the foregoing, it is also understood that VECC may advance arguments that the Company ought to allocate funds as budgeted of $925,000 to low income fuel switching (Ex. 1-24-29). Additionally, the Company agrees that from and after the date of the Board's decision in this proceeding, it will not allocate any portion of the agreed-upon $181.5 million Other O&M budget to any specific marketing, fuel switching or EnergyLink activities that the Board specifically states the Company should not be undertaking.

GEC and Pollution Probe do not agree to the $181.5 million Other O&M budget. GEC and Pollution Probe wish to examine the Company's Opportunity Development (OD) O&M budget separately and do not agree to the overall level of $181.5 million for the Other O&M budget. No other parties, including the Company, will support or argue for any change (increase or decrease) to the agreed-upon Other O&M budget of $181.5 million.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, OAPPA, OESLP, Superior, TransCanada, TransAlta, Union Gas.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue except Pollution Probe and GEC.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Operating Cost Summary
D1-2-1	Operating, Maintenance and Other Costs
D2-1-1	Corporate Cost Allocation
D3-1-1	Operating Cost 2007 Test Year
D3-2-1	Operating Cost Comparison of Utility Cost and Expenses Budget 2007 and Estimate 2006
D3-2-2	Operating and Maintenance Expense by Department
D3-2-3	Operating and Maintenance Expense by Cost Type
I-1-22 to 24	Board Staff Interrogatories 22 to 24
I-2-30 to 35	CCC Interrogatories 30 to 35
I-9-2, 4 and 15	IGUA Interrogatories 2, 4 and 15
I-15-1 to 4	Pollution Probe Interrogatories 1 to 4
I-16-24 to 29	SEC Interrogatories 24 to 29
I-24-27 to 28	VECC Interrogatories 27 to 28
L-9-1	Evidence of IGUA
M1-1-1	Impact Statement #1

3.3 Is the Company's proposed fuel switching program appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-8-1	Opportunity Development – Market Development
I-1-25	Board Staff Interrogatory 25
I-2-36 to 39	CCC Interrogatories 36 to 39
I-7-1	GEC Interrogatory 1
I-22-6	Union Energy Interrogatory 6
I-24-29	VECC Interrogatory 29
I-26-1 to 3	HVAC Interrogatory 1 to 3

3.4 Is the Company's proposed Energy Link program appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Operating Cost Summary
I-22-6	Union Energy Interrogatory 6
I-24-30	VECC Interrogatory 30
I-26-4 to 10	HVAC Interrogatories 4 to 10
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-36 to 46	Enbridge Gas Distribution Interrogatories of Union Energy 36 to 46
I-30-1 to 21	Enbridge Gas Distribution Interrogatories of HVAC 1 to 21

3.5 Is the budget for Human Resources related costs appropriate?

(Complete Settlement)

There is an agreement to settle this issue as part of the package, as follows:

> Parties agree that any Human Resources related costs determined by the Company to be appropriate in the Test Year will be included as part of the agreed-upon $181.5 million Other O&M budget.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-2-1	Operating Costs and Maintenance and Other Costs
D1-2-2	Employee Expenses and Workforce Demographics
D3-2-4	Salaries and Wages and FTE Forecast 2007 Test Year
I-1-26	Board Staff Interrogatory 26
I-2-40 to 43	CCC Interrogatories 40 to 43
I-16-30 to 37	SEC Interrogatories 30 to 37
I-24-31 to 33	VECC Interrogatories 31 to 33

3.6 Do the revisions to the Regulatory Cost Allocation Methodology (RCAM) meet the Board's directives in the 2006 decision?

(No Settlement)

There is no agreement to settle this issue.

The issue of whether the revisions to RCAM meet the Board's directives from the 2006 decision has been a subject of the corporate cost allocation consultative. At this time, the final report from the consultant retained on behalf of the consultative has not been filed. As a result, no settlement can be reached on this issue at this time.

Evidence: The evidence in relation to this issue includes the following:

D2-1-1	Corporate Cost Allocation
G1-1-1	Corporate Cost Allocation Methodology
I-16-38 to 39	SEC Interrogatories 38 to 39

3.7 Is the proposed level of corporate cost allocation for 2007 appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties agree that the Company's O&M budget for corporate cost allocations for the Test Year shall be $18.1 million. Parties agree to the overall level of this budget, but there is no specific agreement as to the amounts of each of the individual allocations.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-2-1	Operating Maintenance and Other Costs
D2-1-1	Corporate Cost Allocation
I-1-27 to 28	Board Staff Interrogatories 27 to 28
I-9-1	IGUA Interrogatory 1
I-24-34 to 37	VECC Interrogatories 34 to 37

3.8 Is Company's forecast level of Regulatory and OEB related costs for 2007 appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> Parties agree that the Company's Regulatory and OEB related costs will be included as part of the agreed-upon Other O&M budget and that variances from the budget for 2007 rate proceeding related expenses will be recorded in the 2007 Ontario Hearings Costs Variance Account for consideration and disposition in a future proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-2-1	Operating Maintenance and Other Costs
D1-9-1	Regulatory Costs
I-1-29 to 30	Board Staff Interrogatories 29 to 30
I-2-44	CCC Interrogatory 44
I-16-40	SEC Interrogatory 40

3.9 Is Enbridge's decision to change to a December 31 taxation year-end , in 2007, appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> Intervenors have relied on the Company's evidence that the change of taxation year-end for the Enbridge Gas Distribution Inc. corporate entity has no impact on the Company's 2007 cost of service. In conjunction with the agreement with respect to Issue 3.15, intervenors accept the Company's evidence in this regard.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-5-1	Taxation Year-End Change

I-1-31 to 34	Board Staff Interrogatories 31 to 34
I-16-41	SEC Interrogatory 41

3.10 Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-4-3	Gas Supply Risk Management
I-1-35 to 36	Board Staff Interrogatories 35 to 36
I-2-45	CCC Interrogatory 45
I-5-18 to 27	Energy Probe Interrogatories 18 to 27
I-18-7	Superior Interrogatory 7
I-24-38 to 39	VECC Interrogatories 38 to 39
L-5-1	Evidence of Energy Probe
I-36-1 to 6	Enbridge Gas Distribution Interrogatories of Energy Probe 1 to 6

3.11 Is the proposal to change depreciation rates for 2007, as proposed in the depreciation study, and the impact on 2007 customer rates, appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> The Company agrees not to proceed with its request to change depreciation rates for 2007. Intervenors agree not to challenge the Company's existing depreciation rates for 2007. Notwithstanding this agreement, parties may examine the existing level of the Company's depreciation rates in the context of discussing and examining other outstanding issues in this proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-13-1	Depreciation Rate Change
D2-2-1	Depreciation Study

I-1-37 to 46	Board Staff Interrogatories 37 to 46
I-5-13 to 14	Energy Probe Interrogatories 13 to 14
I-9-18	IGUA Interrogatory 18
I-16-42 to 41	SEC Interrogatories 42 to 43
I-24-39.1 to 39.3	VECC Interrogatories 39.1 to 39.3
L-9-1	Evidence of IGUA

3.12 Is the proposal for the establishment of 2007 Deferral and Variance Accounts appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

The Company's proposal to establish the following deferral and variance accounts for the Test Year is accepted by the parties for the reasons set out in the Company's evidence:

2007 Purchased Gas Variance Account ("2007 PGVA")
2007 Transactional Services Deferral Account ("2007 TSDA")
2007 Unaccounted for Gas Variance Account ("2007 UAFVA")
2007 Union Gas Deferral Account ("2007 UGDA")
2007 Class Action Suit Deferral Account ("2007 CASDA")
2007 Debt Redemption Deferral Account ("2007 DRDA")
2007 Deferred Rebate Account ("2007 DRA")
2007 Gas Distribution Access Rule Costs Deferral Account ("2007 GDACRDA")
2007 Manufactured Gas Plant Deferral Account ("2007 MGPDA")
2007 Ontario Hearing Costs Variance Account ("2007 OHCVA")
2007 Electric Program Earnings Sharing Deferral Account ("2007 EPESDA")
2007 Unbundled Rate Implementation Cost Deferral Account ("2007 URICDA")
2007 Unbundled Rates Customer Migration Deferral Account ("2007 URCMDA")
2007 Demand-Side Management Variance Account ("2007 DSMVA")
2007 Lost Revenue Adjustment Mechanism ("2007 LRAM")
2007 Shared Savings Mechanism Variance Account ("2007 SSMVA")
2007 Income Tax Rate Change Variance Account ("2007 ITRCVA")

There is no agreement to the establishment of the following deferral and variance accounts, as those accounts are being dealt with as part of the customer care/CIS consultative process and through Issues 7.2 to 7.4:

2007 Customer Information System Procurement Deferral Account ("2007 CISPDA")
2007 Customer Care Procurement Deferral Account ("2007 CCPDA")
2007 Customer Care Supplier Transition Variance Account ("2007 CCSTVA")

There is no agreement to the establishment of the following deferral account, as it is being dealt with as part of the open bill consultative process and through Issue 7.5:

2007 Open Bill Access Sharing Deferral Account ("2007 OBASDA")

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-7-1	Deferral and Variance Accounts
D1-7-3	Deferral and Variance Account Balances
I-1-47	Board Staff Interrogatory 47
I-2-46 to 48	CCC Interrogatories 46 to 48
I-7-2	GEC Interrogatory 2

3.13 Is the proposal for the disposition of existing Deferral and Variance Accounts appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

Enbridge Gas Distribution filed a summary of the actual deferral account and variance account balances for F2006 (D1-7-3); the summary is reproduced in Appendix A. The result of clearing certain of these accounts is that Enbridge Gas Distribution will credit customers $23.258.7 million in principal plus interest, based upon the December 31, 2006 balances, for F2006.

The balances recorded in the following deferral and variance accounts established for F2006, and the proposed clearance of such balances at the same time as the final rate order in this proceeding is implemented, are accepted by the other parties for the reasons given in the supporting evidence:

Non Commodity Related Accounts

2004 Demand-Side Management Variance Account ("2004 DSMVA")
2004 Lost Revenue Adjustment Mechanism ("2004 LRAM")
2004 Shared Savings Mechanism Variance Account ("2004 SSMVA")
2006 Deferred Rebate Account (“2006 DRA”)
2006 Debt Redemption Deferral Account (“2006 DRDA”)
2006 Ontario Hearing Costs Variance Account (“2006 OHCVA”)

Commodity Related Accounts

2006 Unaccounted for Gas Variance Account (“2006 UAFVA”)
2006 Transactional Services Deferral Account (“2006 TSDA”)

2006 Union Gas Deferral Account ("2006 UGDA")

Enbridge Gas Distribution does not seek to clear, in the Test Year, the balances recorded in the following deferral and variance accounts. Parties agree that the following previously-approved deferral and variance accounts are continued and the clearance of these accounts will be addressed by the Board in the future.

<u>Non Commodity Related Accounts</u>

2006 Demand-Side Management Variance Account ("2006 DSMVA")
2005 Demand-Side Management Variance Account ("2005 DSMVA")
2006 Lost Revenue Adjustment Mechanism ("2006 LRAM")
2005 Lost Revenue Adjustment Mechanism ("2005 LRAM")
2006 Shared Savings Mechanism Variance Account ("2006 SSMVA")
2005 Shared Savings Mechanism Variance Account ("2005 SSMVA")
2006 Manufactured Gas Plant Deferral Account (“2006 MGPDA”)
2006 Corporate Cost Allocation Deferral Account (“2006 CCAMDA”)
2006 Class Action Suit Deferral Account (“2006 CASDA”)

<u>Commodity Related Account</u>

2006 Purchased Gas Variance Account ("2006 PGVA")

While Enbridge Gas Distribution seeks to clear the balances recorded in the following deferral and variance accounts in the Test Year, there is no agreement as to whether this is appropriate and these accounts will be addressed at the hearing:

2006 Gas Distribution Access Rule Costs Deferral Account (“2006 GDARCDA”)
2005 Gas Distribution Access Rule Costs Deferral Account (“2005 GDARCDA”)
2006 Alliance Vector Appeal Costs Deferral Account (“2006 AVACDA”)
2006 Gas Supply Risk Management Program Deferral Account (“2006 GSRMPDA”)
2006 Electric Program Earnings Sharing Deferral Account (“2006 EPESDA”)
2006 Unbundled Rate Implementation Cost Deferral Account (“2006 URICDA”)

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-7-1	Deferral and Variance Accounts
D1-7-2	Proposed Clearing of the 2006 Deferral Accounts
D1-7-3	Deferral and Variance Account Balances
A1-13-1	Status of Board Directives from Previous Board Decisions and/or Orders
A3-3-1	Financial Statements – Enbridge Gas Distribution Historical 2005 Year

A3-4-1	Annual Report (Actual) and Management Discussion and Analysis (MD&A)
I-2-49	CCC Interrogatory 49
I-16-44 to 45	SEC Interrogatories 44 to 45
I-24-40	VECC Interrogatory 40

3.14 Are the amounts proposed to be included in rates for capital and property taxes appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

The Company agrees to a $1.3 million reduction in its forecast of municipal property and other taxes for the Test Year.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D3-1-1	Operating Cost 2007 Test Year
I-9-3	IGUA Interrogatory 3
I-2-50	CCC Interrogatory 50

3.15 Is the amount proposed to be included in rates for income taxes, including the methodology, appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties accept the Company's methodology for income taxes, and the amount to be included in rates for income taxes, for the purpose of setting rates for the Test Year, without prejudice to the ability of any party to raise issues with respect to the methodology and its resulting calculations, including but not limited to which inclusions and deductions are appropriate, in future rate proceedings. The Company agrees to create a 2007 Income Tax Rate Change Variance Account to capture the impact of any corporate income tax rate changes against Fiscal 2007 Board Approved taxable income (versus the Company's forecast of corporate income tax rates) that occur in 2007 as a result of Provincial and Federal government budgets that are passed in the Test Year.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

A3-2-1	Financial Statements – Utility Proforma Statements for Bridge and Test Year
A3-3-1	Financial Statements – Enbridge Gas Distribution Historical 2005 Year
A3-4-1	Annual Report (Actual) and Management Discussion and Analysis (MD&A)
A3-5-3	Annual/Audited Financial Reports (Historical) Enbridge Inc. – 2005 Year
D3-1-1	Operating Cost 2007 Test Year
I-16-46 to 47	SEC Interrogatories 46 to 47

4 COST OF CAPITAL (Exhibit E)

4.1 What is the Return on Equity (ROE) for EGDI for the 2007 test year as calculated pursuant to the ROE Guidelines?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Parties agree that the ROE for the Company for the 2007 test year is 8.39%, as calculated pursuant to the ROE guidelines.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Cost of Capital Summary
E1-2-1	Cost of Capital
E2-1-1	Utility Business and Financial Risks
E2-1-2	Enbridge Gas Distribution Utility Business Risks – Environment
E2-1-3	Utility Equity Thickness Financial Risk Update
E2-2-1	Calculation of ROE

E3-1-1	Cost of Capital 2007 Test Year
E3-1-2	Summary Statement of Principal and Carrying Costs of Term Debt 2007 Test Year
E3-1-3	Unamortized Debt Discount and Expense Average of Monthly Averages 2007 Test Year
E3-1-4	Preference Shares Summary Statement of Principal and Carrying Cost 2007 Test Year
E3-1-5	Unamortized Preference Share Issue Expense Average of Monthly Averages 2007 Test Year
E3-1-6	Fiscal 2007 Calculation of Short-term Unfunded Debt
I-5-15	Energy Probe Interrogatory 15
I-24-41 to 43	VECC Interrogatories 41 to 43
M1-1-1	Impact Statement #1

4.2 Are Enbridge's proposed costs for its debt and preference share components of its capital structure appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Cost of Capital Summary
E1-2-1	Cost of Capital
I-1-48	Board Staff Interrogatory 48
I-16-48 to 50	SEC Interrogatories 48 to 50

4.3 Is the proposal to change the equity component of the deemed capital structure from 35% to 38% appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Cost of Capital Summary
E1-2-1	Cost of Capital
E2-1-1	Utility Business and Financial Risks
E2-1-2	Utility Equity Thickness Financial Risk Update
E2-1-2	Enbridge Gas Distribution Utility Business Risks – Environment
E2-2-1	Calculation of ROE
E3-1-1	Cost of Capital 2007 Test Year
I-2-51	CCC Interrogatory 51
I-9-19	IGUA Interrogatory 19
I-16-51 to 54	SEC Interrogatories 51 to 54
I-24-44 to 57	VECC Interrogatories 44 to 57
I-24-77 to 83	VECC Supplementary Interrogatories 77 to 83
L-9	Evidence of IGUA
L-27-1	Evidence of VECC, CCC and IGUA
L-27-2	Supplementary Evidence of VECC, CCC and IGUA
I-28-1 to 17	Enbridge Gas Distribution Interrogatories of VECC, CCC and IGUA 1 to 17

5 COST ALLOCATION (Exhibit G)

5.1 Is the Applicant's cost allocation appropriate and is it based in its 2006 Board approved methodology?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Subject to the comments below in respect of Issues 6.2, 6.4 and 8.1, and subject to a compliance review of the cost allocation that will be embedded in any rate orders arising from this proceeding, parties accept the Company's evidence in this proceeding about its cost allocation for the Test Year and agree that it is appropriate and consistent with the 2006 Board-approved methodology.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransAlta, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	Cost Allocation Methodology
G2-1-1	Fully Allocated Cost Study
I-1-52	Board Staff Interrogatory 52
I-9-20	IGUA Interrogatory 20
I-24-59	VECC Interrogatory 69

5.2 Is the proposal to recover Demand Side Management costs in delivery charges, as opposed to load balancing charges, appropriate?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Parties accept the Company's proposal, as set out in the evidence, to recover Demand Side Management costs in delivery charges, rather than in load balancing charges.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

G2-3-1	Functionalization of Utility Rate Base
G2-3-2	Functionalization of Utility Working Capital
G2-3-3	Functionalization of Utility Net Investments
G2-3-4	Functionalization of Utility O&M
I-1-53	Board Staff Interrogatory 53

6 RATE DESIGN (Exhibit H)

6.1 Is the proposal to introduce delivery demand charges for Rates 100 and 145 reasonable?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Parties accept the Company's proposal, as set out in the evidence, to introduce delivery demand charges for Rates 100 and 145.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue except TransAlta and VECC, which take no position.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
H2-1-1	Revenue Comparison – Current Revenue vs. Proposed Revenue
H2-2-1	Proposed Revenue Recovery by Rate Class
H2-3-1	Summary of Proposed Rate Change by Rate Class
H2-4-1	Calculation of Gas Supply Charges by Rate Class
H2-5-1	Detailed Revenue Calculations by Rate Class
H2-6-1	Rate Handbook
H2-7-1	Annual Bill Comparison
H3-1-1	Revenue Comparison – Current vs Proposed by Rate Class Proposed Methodology
H3-1-2	Proposed Unit Rates by Rate Class
H3-2-1	Proposed Revenue Recovery by Rate Class

H3-3-1	Summary of Proposed Rate Change
H3-4-1	Calculation of Gas Supply Charges by Rate Class
H3-5-1	Detailed Revenue Calculations by Rate Class
H3-6-1	Rate Handbook
H3-7-1	Annual Bill Comparison
I-1-54	Board Staff Interrogatory 54
I-12-1	OAPPA Interrogatory 1

6.2 Is the proposal to allocate revenue requirement between the customer classes and annually adjust the monthly customer charges and variable charges to recover the revenue deficiency reasonable?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue as follows:

> Parties accept the Company's proposal, as set out in the evidence, to annually adjust the monthly customer charges and variable charges to recover the revenue deficiency.
>
> There is no agreement about the Company's proposal to allocate revenue requirement between customer classes. Some parties are concerned that the allocation of the 2007 revenue deficiency as proposed in the Company's evidence results in the collection of revenues greater than allocated costs from Rate 1 and Rate 6 customers based on the Company's filed Revenue to Cost ratios of 1.02 and 1.01 for these rate classes. These parties wish to explore the proposed 2007 revenue requirement allocation in light of the evidence and interrogatory responses on this issue. Other parties support the Company's revenue deficiency allocation and will oppose changes to it.

Participating Parties: All parties participated in the negotiation and settlement of aspects of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada**.**

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
H2-1-1	Revenue Comparison – Current Revenue vs. Proposed Revenue
H2-2-1	Proposed Revenue Recovery by Rate Class
H2-3-1	Summary of Proposed Rate Change by Rate Class
H2-4-1	Calculation of Gas Supply Charges by Rate Class
H2-5-1	Detailed Revenue Calculations by Rate Class
H2-6-1	Rate Handbook

H2-7-1	Annual Bill Comparison
H3-1-1	Revenue Comparison – Current vs Proposed by Rate Class Proposed Methodology
H3-1-2	Proposed Unit Rates by Rate Class
H3-2-1	Proposed Revenue Recovery by Rate Class
H3-3-1	Summary of Proposed Rate Change
H3-4-1	Calculation of Gas Supply Charges by Rate Class
H3-5-1	Detailed Revenue Calculations by Rate Class
H3-6-1	Rate Handbook
H3-7-1	Annual Bill Comparison
I-1-55	Board Staff Interrogatory 55
I-9-23	IGUA Interrogatory 23
I-12-2	OAPPA Interrogatory 2
I-24-70	VECC Interrogatory 70

6.3 Should the Board approve the contents of the Applicant's Rate Handbook?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue as follows:

> Parties agree that it is appropriate for the Board to continue to approve the Company's Rate Handbook, as part of the Rate Order resulting from Rate Case proceedings.
>
> There is no agreement on the Company's proposed Invoice Vendor Adjustment (IVA) charge.
>
> Subject to the issue about the IVA, parties agree that the Rate Handbook as filed should be approved by the Board.

Participating Parties: All parties participated in the negotiation and settlement of this issue except GEC, HVAC, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

A1-14-1	Policies and Regulations of the Company with Respect to Gas Services and Schedule of Service Charges
A1-14-2	Changes to the Schedule of Service Charges
D1-10-2	Gas Distribution Access Rule
H1-1-1	Rate Design
H2-6-1	Rate Handbook
I-19-1	TransAlta Interrogatory 1
I-1-56	Board Staff Interrogatory 56
I-12-3	OAPPA Interrogatory 3
I-24-71 to 73	VECC Interrogatories 71 to 73

6.4 Is the proposed treatment of bundled transportation charges and T-service credit appropriate in light of the Board's Decision in RP-2003-0203 and the settlement agreement?

(Complete Settlement)

There is agreement to settle this issue as follows:

Parties accept the Company's proposed treatment of bundled transportation charges and T-service credits. The final rate increases associated with the implementation of the settlement proposal of the changes in the allocation of upstream transportation charges in EB-2005-0001 will be implemented on October 1st, 2007. Effective October 1, 2007, the upstream transportation charges for all rate classes will recover the appropriate level of upstream transportation costs for all rate classes, so that there will be no over-contribution from Rates 1 and 6 with respect to upstream transportation costs.

The Company will continue to charge and rebate the T-service credit for Ontario T-Service customers. The existing T-Service credit, equal to TransCanada's 100% load factor toll, will continue to be in effect until December 31, 2007. Effective January 1, 2008, the T-Service credit will be based on the weighted average cost of transportation, equal to the unit rate based on total utility transportation costs over total delivery volumes. The Company will treat T-Service credits for Ontario T-Service customers in this manner, as an "off-set", from January 1, 2008 until such time as the Company has a new billing system that permits a different approach. This approach satisfies the Board's directive regarding the Company's obligation to phase-out the T-service credit for Ontario T-Service customers as outlined in the RP-2003-0203 Settlement Proposal.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
I-1-57	Board Staff Interrogatory 57
I-12-4	OAPPA Interrogatory 4

7 CUSTOMER CARE SUPPORT, CUSTOMER CARE SYSTEM, AND OPEN BILL ACCESS

7.1 Has Enbridge complied with the direction, in the EB-2005-0001 Decision, to file in evidence the following Customer Care Support Cost information: all agreements between Enbridge and CWLP, ECSI or any other EI-related entity related to the provision of customer care or CIS; the Program Agreement between CWLP and Accenture, including any amendments or revisions; financial statements for ECSI and CWLP (historical, bridge and test year); the return analyses described in the decision?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

D1-12-1	Customer Care - Overview
D1-12-2	Customer Care and Transition Costs
D1-12-3	Customer Care – Benchmarking
I-1-58	Board Staff Interrogatory 58
I-9-17	IGUA Interrogatory 17
I-16-55 to 58	SEC Interrogatories 55 to 58

7.2 What actions or decisions are required by the Board regarding items in the 2006 and 2007 capital budgets which might be duplicated in the upcoming application for a Regulatory Asset Account?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

D1-10-1	GDAR
I-1-59	Board Staff Interrogatory 59

7.3 Are the forecast costs of the new CIS system appropriate?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

B1-5-1	CIS Project
I-1-60 to 63	Board Staff Interrogatories 60 to 63
I-9-10	IGUA Interrogatory 10
I-26-11	HVAC Interrogatory 11

7.4 What are the appropriate costs for CIS and Customer Care for 2007, including internal and transition costs?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

B1-5-1	CIS Project
D1-12-1	Customer Care – Overview
D1-12-2	Customer Care and Transition Costs
D1-12-3	Customer Care – Benchmarking
D3-2-1	Operating Cost Comparison of Utility Cost and Expenses Budget 2007 and Estimate 2006
I-1-64 to 73	Board Staff Interrogatories 64 to 73
I-16-59	SEC Interrogatory 59

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?

(No Settlement)

There is no agreement to settle this issue, although the consultative is ongoing.

Evidence: The evidence in relation to this issue includes the following:

D1-11-1	Open Bill Access
D1-11-2	Statement of Principles, Objectives and Operating Arrangements for the Consultation Process for Enbridge Gas Distribution's Open Bill Access Proposal
D1-11-3	Open Bill Access Consultative Process
D1-11-4	Meeting Minutes
D1-11-5	Third Party Access Report
D1-11-6	Open Bill Access Update
D1-11-7	Summary Notes from Consultative Meeting on Wednesday July 26, 2006
D1-11-8	Open Bull Access Update – July 26th, 2006
D1-11-9	Summary Notes from Consultative Meeting on Tuesday November 14th, 2006
D1-11-10	Presentation – Consultative Meeting on Tuesday November 14th, 2006
D1-11-11	Open Bill Access Standard Bill Service Consultative November 14th, 2006
D1-11-12	Bill Insert Agreement
D1-11-13	Open Bill Standard Bill Service Description – Meeting November 14th, 2006 – Additional Request for Information
D1-11-14	Bill Inserts
D1-11-15	Bill Insert Agreement Draft
D1-11-16	Initial Draft for Discussion Binding request for Bids – Third Party Bill Inserts for 2007
D1-11-17	Presentation – Consultative Meeting on November 23rd, 2006
D1-11-18	Open Bill Access – Summary Notes from Consultative Meeting on November 23rd, 2006
D1-11-19	Presentation – November 30th, 2006
D1-11-20	Criteria for Bill Inserts
D1-11-21	Open Bill Access – Summary Notes from Conference Call between EGD, Intervenors, and Consultants on Friday, December 1st, 2006
D1-11-22	Shared Bill Benefit Calculation
D1-11-23	Presentation – December 5th, 2006 Corrected Forecast
D1-11-24	Bill Inserts
D1-11-25	Bill Inserts
D1-11-26	Bill Inserts
D1-11-27	Request for Binding Bids – 2007 Third Party Bill Insert Service
D1-11-28	Binding Service Request and Bid Form – 2007 Third Party Bill Insert Service
I-1-74 to 77	Board Staff Interrogatories 74 to 77
I-2-52	CCC Interrogatory 52
I-4-1 to 12	Direct Energy Interrogatories 1 to 12
I-16-60 to 61	SEC Interrogatories 60 to 61
I-18-1 to 5	Superior Interrogatories 1 to 5
I-22-1 to 5	Union Energy Interrogatories 1 to 5
I-24-74 to 75	VECC Interrogatories 74 to 75
I-26-12 to 20	HVAC Interrogatories 12 to 20
L-4-1	Evidence of Direct Energy
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-1 to 35	Enbridge Gas Distribution Interrogatories of Union Energy 1 to 35
I-29-1 to 5	Enbridge Gas Distribution Interrogatories of Direct Energy 1 to 5
I-30-22 to 24	Enbridge Gas Distribution Interrogatories of HVAC 22 to 24
I-32-1 to 5	HVAC Interrogatories of Direct Energy 1 to 5

I-33-1 to 12	Superior Energy Management Interrogatories 1 to 12
I-34-1 to 21	Union Energy Interrogatories of Direct Energy 1 to 21
I-35-1 to 11	Direct Energy Interrogatories of Union Energy 1 to 11
I-36-1 to 16	Direct Energy Interrogatories of HVAC 1 to 16
	Transcript of January 10, 2007 Technical Conference

8 OTHER ISSUES

8.1 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the NGEIR (EB-2005-0551) proceeding will be appropriately captured and reflected in this proceeding?

(Complete Settlement)

There is an agreement to settle this issue as follows:

All parties agree that the implications of the Board's decisions in the NGEIR (EB-2005-0551) proceeding have been captured in the Company's filing in this proceeding. This agreement is subject to the stipulation that certain parties have initiated Motions for Review of the Board's decisions in the NGEIR proceeding which, if successful, could require the Company to make consequential adjustments to its rates, including (without limitation) Rate 316.

The Company's obligations under the NGEIR Settlement Proposal pertaining to whether and when an automated solution should be developed and put in place remain in full force and effect.

Every three months the Company will provide to stakeholders a report on the number of customers that have committed to migrate and have migrated to the new unbundled Rates 300 and 315. If, at any time during the Test Year, 20 customers have committed to take EGD's unbundled rates, the Company will undertake a survey, using the least cost approach, to evaluate demand for unbundled Rates 300 and 315, and assess and report on the timing for development of an automated solution and accommodating additional customers through the manual solution within 90 days after the Company's 20th customer has committed to migrate to the new unbundled rates. If, at that time, the Company decides to proceed with a manual solution, it will continue to provide customers with a quarterly report on the status of migration including feedback from customers on the potential for future migration. The parties agree that the Company's costs associated with preparing and administering the survey will be recorded in the 2007 Unbundled Rate Implementation Cost Deferral Account. The parties further agree they will support recovery by the Company of the reasonably incurred survey costs in the 2007 Unbundled Rate Implementation Cost Deferral

Account on the understanding that the Company will seek to have all reasonably incurred costs recovered from large volume customers.

In order to allow customers to take advantage of the new Rate 300 and Rate 315, customers will have the opportunity to migrate to Rate 300 and 315 at all times during the Test Year until the point in time when 20 customers have migrated to the rate 300 series rates. Subject to the conditions of the Company's Early Termination Policy, the Company will permit migrating customers to terminate their bundled rate contracts early, on the understanding that customers will true up any imbalances in their existing contracts as per the provisions of the Company's Early Termination Policy.

If the survey results indicate that significantly more than 20 customers are prepared to commit to migrate, then the Company will undertake to develop an automated solution. If a smaller number of customers are prepared to commit to migrate, then the Company will conduct an analysis comparing the incremental cost of supporting incremental customers' activities and transactions using the manual solution versus the costs of an automated solution. The goal of the analysis will be to determine if it is feasible to expand the manual solution (and at what cost) versus the cost of an automated solution. Should an automated solution be required, the parties agree that the Company record associated costs in the Unbundled Rate Implementation Cost Deferral Account as per the NGEIR Settlement Proposal EB-2005-0551, Ex. S-1-1, p. 33.

If a manual solution permits more than 20 customers to migrate during the Test Year, any such additional spots will be implemented in a manner that is consistent with section 4(g) of the Settlement Agreement in EB-2005-0551 whereby 50% of the additional spots will be allocated to interested customers who will benefit the most from the service from a distribution rate perspective, and 50% of the additional spots will be allocated to interested customers entitled to subscribe for the service on the basis of a lottery system.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue except VECC which takes no position and did not participate in discussion on the issues discussed after the second paragraph above.

Evidence: The evidence in relation to this issue includes the following:

I-19-1 to 3	TransAlta Interrogatories 1 to 3
I-1-78 to 79	Board Staff Interrogatories 78 to 79
I-12-5 to 6	OAPPA Interrogatories 5 to 6

I-20-1	TransCanada Interrogatory 1

8.2 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the DSM (EB-2006-0021) proceeding will be appropriately captured and reflected in this proceeding?

(Complete Settlement)

There is an agreement to settle this issue as follows:

All parties agree that the implications of the Board's decisions in the DSM (EB-2006-0021) proceeding have been captured in the Company's filing in this proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

I-1-80 to 81	Board Staff Interrogatories 80 to 81
I-9-21 to 22	IGUA Interrogatories 21 to 22
I-24-76	VECC Interrogatory 76

9 RATE IMPLEMENTATION

9.1 How should the Board deal with any revenue deficiency applicable from January 1, 2007 to the date that the Board's decision is implemented?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

Parties agree that the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. Parties agree with and support the Company's proposal to recover the full $26.0 million through (i) increased annualized rates for the remainder of the Test Year; and (ii) the use of a rate rider over the nine remaining months of the Test Year to recover the remaining balance of the $26.0 million. Intervenors agree that no issue or objection will be raised around whether any part of this $26.0 million is unrecoverable because it relates to the time period between January 1, 2007 and April 1, 2007.

There is no agreement as to whether or how the Company can recover any revenue deficiency in excess of $26.0 million.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties except Schools accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

A1-2-1	Application
I-1-82	Board Staff Interrogatory 82
I-16-62 to 53	SEC Interrogatories 62 to 63

9.2 Should the Board set interim rates, effective January 1, 2007, to allow Enbridge to begin to recover its prospective revenue deficiency?

(Complete Settlement)

There is an agreement to settle this issue as follows:

This issue is no longer relevant, since the January 1, 2007 date has passed.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

A1-2-1	Application
I-1-83 to 84	Board Staff Interrogatories 83 to 84
I-16-64 to 65	SEC Interrogatories 64 to 65

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
ACTUAL BALANCES

Line No.	Account Description	Account Acronym	Col. 1 Actual at December 31, 2006 Principal ($000's)	Col. 2 Actual at December 31, 2006 Interest ($000's)	Col. 3 Accounts Agreed to be cleared with Final Rate Order Actual Balances at December 31, 2006 Principal ($000's)	Col. 4 Accounts Agreed to be cleared with Final Rate Order Actual Balances at December 31, 2006 Interest ($000's)	
	Non Commodity Related Accounts for One Time Rate Clearance						
1.	Demand Side Management Account	2006 DSMVA	374.7	(39.4)	-	-	
2.	Demand Side Management Account	2005 DSMVA	697.5	(9.7)	-	-	
3.	Demand Side Management Account	2004 DSMVA	2,013.9	149.1	2,013.9	149.1	
4.	Lost Revenue Adjustment Mechanism	2006 LRAM	-	-	-	-	
5.	Lost Revenue Adjustment Mechanism	2005 LRAM	-	-	-	-	
6.	Lost Revenue Adjustment Mechanism	2004 LRAM	(587.9)	13.6	(587.9)	13.6	
7.	Shared Savings Mechanism	2006 SSMVA	-	-	-	-	
8.	Shared Savings Mechanism	2005 SSMVA	-	-	-	-	
9.	Shared Savings Mechanism	2004 SSMVA	-	-	-	-	
10.	Class Action Suit D/A	2006 CASDA	23,514.2	117.1	-	-	
11.	Deferred Rebate Account	2006 DRA	(1,904.7)	(103.5)	(1,904.7)	(103.5)	
12.	Debt Redemption D/A	2006 DRDA	-	-	-	-	
13.	Ontario Hearing Costs V/A	2006 OHCVA	(612.8)	-	(612.8)	-	
14.	Manufactured Gas Plant D/A	2006 MGPDA	39.0	0.7	-	-	
15.	Electric Program Earnings Sharing D/A	2006 EPESDA	(175.1)	-	-	-	
16.	Corporate Cost Allocation	2006 CCAMDA	623.7	0.6	-	-	
17.	Unbundled Rate Implementation Cost D/A	2006 URICDA	480.5	-	-	-	
18.	Alliance/Vector Appeal Costs D/A	2006 AVACDA	529.2	17.3	-	-	
19.	Total Non Commodity Related Accounts for One Time Rate Clearance		24,992.2	145.8	(1,091.5)	59.2	
	Commodity Related Accounts for One Time Rate Clearance						
20.	2006 Purchased Gas V/A	2006 PGVA	(125,122.4)	(2,237.9)	-	-	a)
21.	2006 Transactional Services D/A	2006 TSDA	(7,508.8)	(15.5)	(7,508.8)	(15.5)	
22.	2006 Unaccounted for Gas V/A	2006 UAFVA	(11,739.1)	-	(11,739.1)	-	
23.	2006 Union Gas D/A	2006 UGDA	(2,919.3)	49.8	(2,919.3)	49.8	
24.	Total Commodity Related Accounts for One Time Rate Clearance		(147,289.6)	(2,203.6)	(22,167.2)	34.3	
25.	Total Deferral and Variance Accounts for One Time Rate Clearance		(122,297.4)	(2,057.8)	(23,258.7)	93.5	
	Non Commodity Related Accounts for Rate Base and Ongoing Rates Treatment						
26.	Gas Distribution Access Rule Costs D/A	2006 GDARCDA	7,923.3	62.1	-	-	b)
27.	Gas Distribution Access Rule Costs D/A	2005 GDARCDA	406.0	29.2	-	-	b)
28.	Gas Supply Risk Management Program D/A	2006 GSRMPDA	691.5	-	-	-	b)
29.	Total Deferral and Variance Accounts for Rate Base and Ongoing Rates Treatment		9,020.8	91.3	-	-	

Note: a) PGVA and related adjustments to be handled as part of April 2007 QRAM.

Note: b) These accounts would be required to be closed into rate base, with associated revenue requirement impacts, pending the hearing review and any eventual Board Approval.

EGD 2007 ADR PROPOSAL
BASED ON REVENUE DEFICIENCY OF $26 MILLION
FINAL

Rate Class	Impacts Relative to July 1, 2006 T-service Rates: Revenue to Cost Ratios 2007	Revenue to Cost Ratios 2006	Over/Under Contribution 2007	Over/Under Contribution 2006	Average Rate Impact T-Service	Impact Relative to January 1, 2007 T-service Rates: Average Rate Impact T-Service	TCPL Phase In Contribution
			$/M	$/M			$/M
1	1.01	1.01	10.35	8.75	2.07%	2.08%	5.01
6	1.01	1.01	5.06	4.19	0.66%	0.67%	4.89
9	0.69	0.69	-0.47	-0.59	6.44%	6.45%	0.00
100	0.97	0.98	-3.48	-2.92	1.91%	1.92%	0.00
110	1.01	1.01	0.38	0.33	-0.85%	-0.84%	0.00
115	0.90	0.90	-4.18	-5.49	0.96%	0.97%	-5.97
135	0.87	0.87	-0.28	-0.33	1.25%	1.25%	-0.60
145	0.97	1.03	-0.49	0.42	1.62%	1.63%	0.00
170	0.81	0.89	-4.98	-3.48	1.76%	1.76%	-3.20
200	0.98	0.98	-0.22	-0.20	4.60%	4.60%	0.00

Note: 2006 and 2007 Over/Under Contributions need to be adjusted by the TCPL phase in contribution amount to reflect the post October 1, 2007 situation.

EGD 2007 ADR PROPOSAL
BASED ON REVENUE DEFICIENCY OF $82.1 MILLION

Rate Class	Revenue to Cost Ratios 2007	Revenue to Cost Ratios 2006	Over/Under Contribution 2007	Over/Under Contribution 2006	Average Rate Impact T-Service	TCPL Phase In Contribution
			$/M	$/M		$/M
1	1.01	1.01	9.35	8.75	6.28%	5.01
6	1.01	1.01	5.42	4.19	4.52%	4.89
9	0.70	0.69	-0.48	-0.59	13.19%	0.00
100	0.98	0.98	-2.98	-2.92	5.48%	0.00
110	1.01	1.01	0.43	0.33	1.04%	0.00
115	0.90	0.90	-4.18	-5.49	1.96%	-5.97
135	0.87	0.87	-0.28	-0.33	2.54%	-0.60
145	0.97	1.03	-0.48	0.42	4.08%	0.00
170	0.82	0.89	-4.82	-3.48	4.24%	-3.20
	0.00		0.00			
200	0.98	0.98	-0.16	-0.20	7.70%	0.00

Note: 2006 and 2007 Over/Under Contributions need to be adjusted by the TCPL phase in contribution amount to reflect the post October 1, 2007 situation.

SUPPLEMENTARY SETTLEMENT PROPOSAL : ISSUE 7.5

The issues related to Issue 7.5 ("Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?") have been the subject of the ongoing Open Bill Consultative. Parties have been able to come to an agreement to settle aspects of this issue.

This incomplete settlement, if approved by the Board, will be added to the Settlement Proposal (Ex. N1-1-1) approved by the Board on January 29, 2007 (the "January 29th Settlement Proposal") and the provisions of this incomplete settlement will supersede the reference at page 43 of 47 of the January 29th Settlement Proposal which states that there is no settlement of Issue 7.5.

Parties agree that the provisions of the Introduction and Overview sections of the January 29th Settlement Proposal apply to this Supplementary Settlement Proposal, except for (i) the chart of settled issues, which does not reflect this incomplete settlement of Issue 7.5; and (ii) any references to revenue deficiency and rate impact of the settlement, which would have to be changed to reflect the incremental financial impact of this Supplementary Settlement Proposal.

With that preamble, the following section represents the incomplete settlement that has been agreed upon.

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as follows:

The parties agree to settle the third party billing component ("Billing Services") of Issue 7.5 Open Bill Access on the basis that the Company can proceed with the Billing Services on the following terms:

1. ***Compliance with Board Directive.*** All parties accept the Company's decision to respond to the Board's directive in EB-2005-0001 in two stages: an interim solution, using the Company's existing CIS, and a comprehensive solution, using the Company's planned new CIS. This settlement constitutes the interim solution until otherwise ordered by the Board in the Board review referred to in #2 below. Subject to the

presentation to the Board of the comprehensive solution, discussed in #2 below, all parties agree that this settlement constitutes an appropriate response to the Board's directive.

2. ***Comprehensive Solution.*** The Company agrees that it will file an application to the Board prior to the end of 2008 proposing the comprehensive Billing Services offering. Such application should include: a) a detailed report on the experience with the interim solution, b) any available consultants' reports with respect to costing and/or market pricing, c) the results of any customer communications activities and any customer or industry surveys, d) minutes and/or reports of the activities of the stakeholder committee referred to in #8 below, and e) the Company's proposal on whether the Billing Services should continue, and if so on what terms. Without limiting the generality of the foregoing, the Company's proposal may include changes to pricing, costing, shareholder incentive, and any other aspects of the Billing Services. In the event that in the Company's application the Company or any party proposes that the Billing Services should not continue, that party must also propose a reasonable transition period to reflect the time required for anyone using the Billing Services to shift to alternate billing arrangements. Nothing in this settlement implies that any party admits to either the relevance or the appropriate weight to be given to any particular evidence in this subsequent application, and all parties will be free to argue as they see fit with respect to any proposed evidence.

3. ***Pricing.*** During the interim period, but at least until December 31, 2008 parties accept the prices proposed by the Company, $0.829 for shared bills and $1.389 for standalone bills. All participants using the Billing Services will pay the same prices for the same services. The parties agree that prices for the Billing Services and any changes from time to time to the rules relating to the OBSDA referred to in #4 below must be approved by the Board.

4. ***Startup Costs.*** The shareholder will bear the startup and bill re-design costs associated with the Billing Services but will be allowed to recover 4 cents/bill from the Open Bill Service Deferral Account (OBSDA) over a two year period until the costs are recovered. The shareholder will not bear the costs associated with adding the Billing Services to the new CIS. The latter costs will be included in the costs of the Billing Services and recovered in revenues from the service.

5. ***Ratepayer Benefit.*** Subject to the shareholder incentive, set forth below, all net benefits, whether through mitigation of common costs, or net profits from the OBA services, will accrue to the benefit of the ratepayers. The Company agrees to include in its 2007 revenue requirement a net benefit of the service of $5.389 million. This number is derived from calculations /u found in JT.5, as updated to reflect this settlement. To be sure, all parties also agree If the net benefit of the service is greater or less than the amount included in rates, the difference will be credited or debited, as the case may be, to a new variance account, the Open Bill Access Variance Account (OBAVA) and refunded or charged to ratepayers in the following year. The net benefit shall be calculated as the total revenues from Billing Services, less

   a. the incremental costs to deliver those services;
   b. the amount referred to in #4 above; and,
   c. the shareholder incentive referred to in #6 below.

6. ***Shareholder Incentive.*** The Company will receive no incentive for Billing Services provided to any affiliate of the Company. For the Billing Services by any other person, the Company will be paid a commission as follows subject to an annual maximum calculated as 50% of the program's net margin:
   a. With respect to any bill on which Direct Energy (which for all purposes of these terms should be interpreted as including any successor to Direct Energy's water heater business) is the sole third party billing entity, $0.02 per bill;

   b. With respect to any bill on which there is any third party billing entity charge other than Direct Energy on the bill:

      i. $0.10 per bill in any month that the Billing Services service has only one active billing entity other than affiliates or Direct Energy;
      ii. $0.15 per bill in any month that the Billing Services service has two active billing entities other than affiliates or Direct Energy;
      iii. $0.20 per bill in any month that the Billing Services service has three active billing entities other than affiliates or Direct Energy;
      iv. $0.25 per bill in any month that the Billing Services service has more than three active billing entities other than affiliates or Direct Energy;

An entity will only be considered an "active billing entity" in any month in which it is billing products or services on at least 500 EGD bills.

7. ***Costing and Pricing Studies:*** The Company agrees that it will retain an independent consultant or consultants to undertake costing and pricing analyses for the Billing Services. The consultant's work will include assistance in determining a market price, and a review and analysis of the incremental and fully-allocated costs of these services. The Company will solicit the stakeholder group's input on the independent consultant(s), and statement of work for those consultant(s), but the Company will retain the right to make the final selection and define the terms of the reference. The cost of these studies will be included in the OBSDA.

8. ***Stakeholder Input.*** The Company will establish a stakeholder committee that includes users of the Billing Services, as well as ratepayer and industry representatives, to review the rules associated with participation in Billing Services. All parties to the agreement will be invited to become members of the stakeholder committee. The committee will meet from time to time as required to consider changes to the rules. Any changes to the rules that materially change the nature of the service will be reviewed by the stakeholder committee and reported to the Board to determine if their approval is required. The stakeholder committee will also be solicited for input into the Company's proposed communications plan, and other issues as they arise.

9. ***Affiliate Participation.*** Affiliates of the Company (including for the purpose of this settlement related parties such as limited partnerships or trusts that are not technically affiliates) may use the Billing Services on the same terms as any other third party biller. However, all parties agree with the principle that the Billing Services should be implemented in a manner that avoids ratepayer and/or consumer confusion, and, to the extent possible, prevents any participant from gaining any unfair market advantage by reason of their association with the utility, if any. The Company agrees that during the interim period it will implement such measures as may be necessary to achieve this principle, including but not limited to including in the Billing Services and enforcing in a commercially reasonable manner the following service rules::

   (a) No person, whether affiliate or otherwise, may use or associate itself with any name or logo on the bill that is the same as, similar to, or confusing with any name or logo that is associated with the Company (e.g. the "Enbridge" name and swirl logo).

(b) No person may use the Billing Services in an abusive or unfair manner in that it deliberately creates the impression that it has a preferred position relative to other market participants because of its relationship with the utility.

Notwithstanding, these restrictions in no way shape or form creates any future precedent to rely upon regarding the use of the Enbridge name or logo.

The parties acknowledge their mutual intention to bring issues with respect to affiliate participation to the stakeholder committee for resolution, but this statement will not limit any rights any party may have, whether under the Affiliate Relationships Code or otherwise, to have disputes resolved in any forum.

10. ***EnergyLink™ Relevance.*** If the Board in this proceeding approves the EnergyLink™ program proposed by the Company, the parties agree that whether a company is an EnergyLink™ participant or not will not affect whether that company can use the Billing Services, nor the rules or conditions under which they use the service.

11. ***Information.*** The Company will develop with input from the stakeholder committee an appropriate customer communication plan specific to Billing Services The Company shall provide to the Board and make available to all parties to this settlement agreement a report that includes revenues from Billing Services, and the costs of the services on a fully-allocated basis,an incremental basis and in a manner when known that is consistent with the methodology recommended in the study noted in paragraph 7, to the extent that this is different .

12. ***Logos and Bill Messaging.*** Logos and bill messaging will be provided to all participants in the Billing Services at no charge to facilitate entry of new users and help consumers differentiate the various parties with amounts billed on the EGD bill. Any provision of logos and bill messaging for the Billing Services will apply in the same manner to commodity vendors using the ABC Services for a reasonable charge, but commodity messaging will not be allowed unless EGD or one of its affiliates starts to market system gas.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Energy Probe, IGUA, OAPPA, Superior, TransAlta, TransCanada and Union Gas,

Approval: All participating parties accept and agree with the proposed settlement of this issue except that GEC and Pollution Probe reserve the right to pursue in the Hearing whether the Board should order that third parties not be allowed to use the Billing Services for the billing of specific products on the basis of their environmental attributes.

Evidence: The evidence in relation to this issue includes the following:

D1-11-1	Open Bill Access
D1-11-2	Statement of Principles, Objectives and Operating Arrangements for the Consultation Process for Enbridge Gas Distribution's Open Bill Access Proposal
D1-11-3	Open Bill Access Consultative Process
D1-11-4	Meeting Minutes
D1-11-5	Third Party Access Report
D1-11-6	Open Bill Access Update
D1-11-7	Summary Notes from Consultative Meeting on Wednesday July 26, 2006
D1-11-8	Open Bull Access Update – July 26th, 2006
D1-11-9	Summary Notes from Consultative Meeting on Tuesday November 14th, 2006
D1-11-10	Presentation – Consultative Meeting on Tuesday November 14th, 2006
D1-11-11	Open Bill Access Standard Bill Service Consultative November 14th, 2006
D1-11-12	Bill Insert Agreement
D1-11-13	Open Bill Standard Bill Service Description – Meeting November 14th, 2006 – Additional Request for Information
D1-11-14	Bill Inserts
D1-11-15	Bill Insert Agreement Draft
D1-11-16	Initial Draft for Discussion Binding request for Bids – Third Party Bill Inserts for 2007
D1-11-17	Presentation – Consultative Meeting on November 23rd, 2006
D1-11-18	Open Bill Access – Summary Notes from Consultative Meeting on November 23rd, 2006

D1-11-19	Presentation – November 30th, 2006
D1-11-20	Criteria for Bill Inserts
D1-11-21	Open Bill Access – Summary Notes from Conference Call between EGD, Intervenors, and Consultants on Friday, December 1st, 2006
D1-11-22	Shared Bill Benefit Calculation
D1-11-23	Presentation – December 5th, 2006 Corrected Forecast
D1-11-24	Bill Inserts
D1-11-25	Bill Inserts
D1-11-26	Bill Inserts
D1-11-27	Request for Binding Bids – 2007 Third Party Bill Insert Service
D1-11-28	Binding Service Request and Bid Form – 2007 Third Party Bill Insert Service
D1-11-29	Third Party Access to the Bill Customer Communication Plan
D1-11-30	Billing Insert Customer Communication Plan
I-1-74 to 77	Board Staff Interrogatories 74 to 77
I-2-52	CCC Interrogatory 52
I-4-1 to 12	Direct Energy Interrogatories 1 to 12
I-16-60 to 61	SEC Interrogatories 60 to 61
I-18-1 to 5	Superior Interrogatories 1 to 5
I-22-1 to 5	Union Energy Interrogatories 1 to 5
I-24-74 to 75	VECC Interrogatories 74 to 75
I-26-12 to 20	HVAC Interrogatories 12 to 20
L-4-1	Evidence of Direct Energy
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-1 to 35	Enbridge Gas Distribution Interrogatories of Union Energy 1 to 35
I-29-1 to 5	Enbridge Gas Distribution Interrogatories of Direct Energy 1 to 5
I-30-22 to 24	Enbridge Gas Distribution Interrogatories of HVAC 22 to 24
I-32-1 to 5	HVAC Interrogatories of Direct Energy 1 to 5
I-33-1 to 12	Superior Energy Management Interrogatories 1 to 12
I-34-1 to 21	Union Energy Interrogatories of Direct Energy 1 to 21
I-35-1 to 11	Direct Energy Interrogatories of Union Energy 1 to 11
I-36-1 to 16	Direct Energy Interrogatories of HVAC 1 to 16
	Transcript of January 10, 2007 Technical Conference
JT1-JT22	Undertakings from January 10, 2007 Technical Conference

SUPPLEMENTARY SETTLEMENT PROPOSAL : ISSUE 7.5

The issues related to Issue 7.5 ("Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?") have been the subject of the ongoing Open Bill Consultative. Parties have been able to come to an agreement to settle aspects of this issue.

This incomplete settlement, if approved by the Board, will be added to the Settlement Proposal (Ex. N1-1-1) approved by the Board on January 29, 2007 (the "January 29th Settlement Proposal") and the provisions of this incomplete settlement will supersede the reference at page 43 of 47 of the January 29th Settlement Proposal which states that there is no settlement of Issue 7.5.

Parties agree that the provisions of the Introduction and Overview sections of the January 29th Settlement Proposal apply to this Supplementary Settlement Proposal, except for (i) the chart of settled issues, which does not reflect this incomplete settlement of Issue 7.5; and (ii) any references to revenue deficiency and rate impact of the settlement, which would have to be changed to reflect the incremental financial impact of this Supplementary Settlement Proposal.

With that preamble, the following section represents the incomplete settlement that has been agreed upon.

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?

(Incomplete Settlement)

There is an agreement of some parties to settle aspects of this issue, as follows:

Proposed Billing Insert Settlement

The parties agree to settle the billing insert ("Insert Service") component of Issue 7.5 Open Bill Access on the basis that the Company can proceed with the Insert Service on the following terms:

1. ***Compliance with Board Directive.*** All parties accept the Company's decision to respond to the Board's directive in EB-2005-0001 in two stages: an interim solution, using the Company's existing CIS, and a comprehensive solution, using the Company's planned new CIS. This settlement constitutes

the interim solution until otherwise ordered by the Board in the Board review referred to in #2 below. Subject to the presentation to the Board of the comprehensive solution, discussed in #2 below, all parties agree that this settlement constitutes an appropriate response to the Board's directive as it pertains to bill inserts.

2. ***Comprehensive Solution.*** The Company agrees that it will file an application to the Board prior to the end of 2008 proposing the comprehensive Billing Insert Service offering. Such application should include: a) a detailed report on the experience with the interim solution, b) any available consultants' reports with respect to costing and/or market pricing, c) the results of any customer communications activities and any customer or industry surveys, d) minutes and/or reports of the activities of the stakeholder committee referred to in #8 below, and e) the Company's proposal on whether the Insert Service should continue, and if so on what terms. Without limiting the generality of the foregoing, the Company's proposal may include changes to pricing, costing, shareholder incentive, and any other aspects of the Insert Service. Nothing in this settlement implies that any party admits to either the relevance or the appropriate weight to be given to any particular evidence in this subsequent application, and all parties will be free to argue as they see fit with respect to any proposed evidence.

3. ***Pricing.*** For the interim period of 2007 and 2008, the Company agrees to reduce the minimum bids for bill inserts by one cent resulting in an average insert charge of 4 cents. For greater clarity, there shall be no right of first refusal for parties using the Company's Insert Service. The parties agree that prices for the Insert Service, and any changes thereto from time to time, must be approved by the Board.

4. ***Costing and Pricing. T***he Company agrees that it will retain an independent consultant to undertake a costing and pricing analysis for the Bill Insert Service for the comprehensive period. The consultant's work will include assistance in determining a market price, and a review and analysis of the incremental and fully-allocated costs of these services for the new CIS. The Company will solicit the stakeholder group's input on the independent consultant, and statement of work for that consultant, but the Company will retain the right to make the final selection and define the terms of the reference. The cost of this study will be included in the Open Bill Service Deferral Account (OBSDA).

5. ***Startup Costs.*** The shareholder will record the startup costs associated with the Insert Service in 2007 in the OBSDA. The startup costs associated with

adding the Insert Service to the new CIS will be included in the costs of the Insert Service and recovered in revenues from the service.

6. ***Ratepayer Benefit.*** The Company agrees to record the costs and revenues from the Insert Service in 2007 in the OBSDA and that the net proceeds will be shared 50/50. The parties agree that the shareholder incentive mechanism for Insert Service may need to be revised after the interim period and after the cost/price review to be consistent with the Board's rules for natural gas incentive regulation.

7. ***Inserts.*** Bill inserts would be allowed as proposed by EGD but revised to limit the number of external inserts to five (5) when safety inserts are scheduled. In all months, two inserts would be reserved for parties wishing to purchase bill inserts in a limited geographic area based on price per insert bidding.

8. ***Stakeholder Input.*** The Company will establish a stakeholder committee that includes users of the Insert Service, as well as ratepayer and industry representatives, to review the rules associated with participation in the Insert Services. All parties to the agreement will be invited to become members of the stakeholder committee. The committee will meet from time to time as required to consider changes to the rules. Any changes to the rules that materially change the nature of the service will be reviewed by the stakeholder committee and reported to the Board to determine if their approval is required. The stakeholder committee will also be solicited for input into the Company's proposed communications plans, and other issues as they arise. To ensure that consumer interests are being addressed, EGD will conduct focus groups and customer surveys on inserts as soon as possible in 2007 and report the findings to the stakeholder committee to determine if remedial action is required. EGD will also prescreen insert users and review the content of their bill inserts to ensure proper use of its billing envelope.

9. ***Problem Resolution.*** If the revised bidding and allocation processes restrict access in three consecutive months or the number of customer complaints on inserts increases significantly in the first two months of operation, the stakeholder committee would be convened to address the concern(s), and if the problem cannot be resolved within two (2) additional months that aspect of the Insert Service would be discontinued until the problem is addressed.

10. ***Affiliate Participation.*** Affiliates of the Company (including for the purpose of this settlement related parties such as limited partnerships or trusts that are

not technically affiliates) may use the Insert Service on the same terms as any other third party biller. However, all parties agree with the principle that the Insert Service should be implemented in a manner that avoids ratepayer and/or consumer confusion, and, to the extent possible, prevents any participant from gaining any unfair market advantage by reason of their association with the utility, if any. The Company agrees that during the interim period it will implement such measures as may be necessary to achieve this principle, including but not limited to including in the Insert Services and enforcing in a commercially reasonable manner the following service rules::

(a) No person, whether affiliate or otherwise, may use or associate itself with any name or logo in the billing envelope that is the same as, similar to, or confusing with any name or logo that is associated with the Company (e.g. the “Enbridge” name and swirl logo).

(b) No person may use the Insert Service in an abusive or unfair manner in that it deliberately creates the impression that it has a preferred position relative to other market participants because of its relationship with the utility.

Notwithstanding, these restrictions in no way shape or form creates any future precedent to rely upon regarding the use of the Enbridge name or logo.

The parties acknowledge their mutual intention to bring issues with respect to affiliate participation to the stakeholder committee for resolution, but this statement will not limit any rights any party may have, whether under the Affiliate Relationships Code or otherwise, to have disputes resolved in any forum.

11. ***EnergyLink^{TM} Relevance.*** If the Board in this proceeding approves the EnergyLink***TM*** program proposed by the Company, the parties agree that whether a company is an EnergyLink***TM*** participant or not will not affect whether that company can use the Insert Service, nor the rules or conditions under which they use the service, subject to the restriction on use of the Enbridge name and logo as described in Item 10 above.

12. This agreement should not be construed as a settlement of any aspect of issue 3.4, including but not limited to, arguments to restrict the Company’s ability to promote EnergyLink ***TM*** by bill insert or otherwise. Notwithstanding, the Company agrees to provide a schedule of EnergyLink ***TM*** inserts on an annual basis, as part of the Binding Request for Bids process.

13. ***Commodity Marketing.*** Commodity bill inserts and marketing will not be allowed in the billing envelope unless EGD or one of its affiliates receives OEB approval to promote and/or market system gas commodity, in which case retailers, marketers and vendors will be allowed to promote and/or market their commodity offers through the Insert Service.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Energy Probe, IGUA, OAPPA, TransAlta, TransCanada and Union Gas,

Approval: Enbridge Gas Distribution, Direct Energy, OESLP and Union Energy accept and agree with this proposed settlement. HVAC, VECC and Schools do not agree with the proposed settlement. CCC opposes the proposed settlement in order that it may be permitted to pursue cross-examination on the issue. GEC and Pollution Probe reserve the right to pursue in the Hearing whether the Board should order that third parties not be allowed to use the Billing Services for the billing of specific products on the basis of their environmental attributes. Superior opposes the proposed settlement on the principle that it is not supportive of a settlement position that would allow for the Company to promote system gas through billing inserts as contemplated in Paragraph 13.

Evidence: The evidence in relation to this issue includes the following:

D1-11-1	Open Bill Access
D1-11-2	Statement of Principles, Objectives and Operating Arrangements for the Consultation Process for Enbridge Gas Distribution's Open Bill Access Proposal
D1-11-3	Open Bill Access Consultative Process
D1-11-4	Meeting Minutes
D1-11-5	Third Party Access Report
D1-11-6	Open Bill Access Update
D1-11-7	Summary Notes from Consultative Meeting on Wednesday July 26, 2006
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D1-11-9	Summary Notes from Consultative Meeting on Tuesday November 14th, 2006
D1-11-10	Presentation – Consultative Meeting on Tuesday November 14th, 2006
D1-11-11	Open Bill Access Standard Bill Service Consultative November 14th, 2006
D1-11-12	Bill Insert Agreement
D1-11-13	Open Bill Standard Bill Service Description – Meeting November 14th, 2006 – Additional Request for Information
D1-11-14	Bill Inserts
D1-11-15	Bill Insert Agreement Draft
D1-11-16	Initial Draft for Discussion Binding request for Bids – Third Party Bill Inserts for 2007

D1-11-17	Presentation – Consultative Meeting on November 23rd, 2006
D1-11-18	Open Bill Access – Summary Notes from Consultative Meeting on November 23rd, 2006
D1-11-19	Presentation – November 30th, 2006
D1-11-20	Criteria for Bill Inserts
D1-11-21	Open Bill Access – Summary Notes from Conference Call between EGD, Intervenors, and Consultants on Friday, December 1st, 2006
D1-11-22	Shared Bill Benefit Calculation
D1-11-23	Presentation – December 5th, 2006 Corrected Forecast
D1-11-24	Bill Inserts
D1-11-25	Bill Inserts
D1-11-26	Bill Inserts
D1-11-27	Request for Binding Bids – 2007 Third Party Bill Insert Service
D1-11-28	Binding Service Request and Bid Form – 2007 Third Party Bill Insert Service
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I-4-1 to 12	Direct Energy Interrogatories 1 to 12
I-16-60 to 61	SEC Interrogatories 60 to 61
I-18-1 to 5	Superior Interrogatories 1 to 5
I-22-1 to 5	Union Energy Interrogatories 1 to 5
I-24-74 to 75	VECC Interrogatories 74 to 75
I-26-12 to 20	HVAC Interrogatories 12 to 20
L-4-1	Evidence of Direct Energy
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-1 to 35	Enbridge Gas Distribution Interrogatories of Union Energy 1 to 35
I-29-1 to 5	Enbridge Gas Distribution Interrogatories of Direct Energy 1 to 5
I-30-22 to 24	Enbridge Gas Distribution Interrogatories of HVAC 22 to 24
I-32-1 to 5	HVAC Interrogatories of Direct Energy 1 to 5
I-33-1 to 12	Superior Energy Management Interrogatories 1 to 12
I-34-1 to 21	Union Energy Interrogatories of Direct Energy 1 to 21
I-35-1 to 11	Direct Energy Interrogatories of Union Energy 1 to 11
I-36-1 to 16	Direct Energy Interrogatories of HVAC 1 to 16
	Transcript of January 10, 2007 Technical Conference
JT1-JT22	Undertakings from January 10, 2007 Technical Conference

SUPPLEMENTARY SETTLEMENT PROPOSAL : ISSUE 6.3

The Settlement Proposal filed as Exhibit N1, Tab 1, Schedule 1, which was approved by the Board on January 29, 2007 (the "January 29th, 2007 Settlement Proposal"), notes at page 39 of 47 that Issue 6.3 was an Incomplete Settlement. Specifically, there was no agreement on the Company's proposed Invoice Vendor Adjustment (IVA) charge. Discussions have continued in respect of the IVA charge and Parties have been able to come to an agreement to settle outstanding issues relating to the IVA charge.

If this Supplementary Settlement Proposal for the IVA charge is approved by the Board, it will be added to the January 29th, 2007 Settlement Proposal, and the provisions of this Supplementary Settlement Proposal will supersede the reference at page 39 of 47 of the January 29th, 2007 Settlement Proposal which states that there is No Settlement in respect of the IVA charge.

Parties agree that the provisions of the Introduction and Overview sections of the January 29th, 2007 Settlement Proposal apply to this Supplementary Settlement Proposal, except for the chart of settled issues, which does not reflect the complete settlement of Issue 6.3.

With this preamble, the following section represents the complete settlement that has been agreed upon.

6.3 Should the Board approve the contents of the Applicant's Rate Handbook?

(Complete Settlement)

There is an agreement to settle aspects of this issue, as follows:

The parties agree that:

1. The IVA charge by the Company will equal 0.65% of the absolute dollar value of the adjustment. Parties agree that this IVA charge is an interim measure that will apply from June 1, 2007 to December 31, 2007, and is without prejudice to any Party proposing an alternative IVA charge commencing January 1, 2008.

2. The Company will consult with interested parties and will consider the merits of bringing forward a different fee structure for a cost-based IVA charge. The Company will seek approval from the OEB for the new IVA charge, to be effective January 1, 2008.

3. Parties agree that the IVA charge is designed to only recover the costs incurred by the Company to provide this service. As a result, Parties agree that there is no need to adjust the revenue deficiency as a result of forecast IVA charge revenues and costs. The Company will provide parties with a summary of 2007 IVA charge revenues and costs subsequent to December 31, 2007.

Participating Parties**:** All parties participated in the negotiation and settlement of this issue except Energy Probe, GEC, HVAC, LIEN, OAPPA, Pollution Probe, SEC, Superior, TransCanada, TransAlta, Union Energy and Union Gas.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue. Without limiting the generality of the Introduction to the Settlement Proposal, VECC's acceptance of this proposed settlement is without prejudice to it proposing that IVA charges be reviewed as part of the Board's generic review of the QRAM/System Gas. CCC, HVAC, IGUA, Energy Probe, SEC, and Union Energy take no position.

Evidence: The evidence in relation to this issue includes the following:

D1-10-2, plus attachment	Gas Distribution Access Rule
Tr. 5, pp. 68, 73-74	

SETTLEMENT PROPOSAL FOR CUSTOMER CARE AND CUSTOMER INFORMATION SYSTEM ("CIS") ISSUES

I. PREAMBLE

The following issues related to Enbridge Gas Distribution's Customer Care O&M and Customer Information System ("CIS") capital budgets, and related matters, have been among the subjects addressed as part of the ongoing Customer Care/CIS Consultative:

7.1 Has Enbridge complied with the direction, in the EB-2005-0001 Decision, to file in evidence the following Customer Care Support Cost information: all agreements between Enbridge and CWLP, ECSI or any other EI-related entity related to the provision of customer care or CIS; the Program Agreement between CWLP and Accenture, including any amendments or revisions; financial statements for ECSI and CWLP (historical, bridge and test year); the return analyses described in the decision? (D1-12-3)

7.2 What actions or decisions are required by the Board regarding items in the 2006 and 2007 capital budgets which might be duplicated in the upcoming application for a Regulatory Asset Account? (D1-10-1, p. 2/AppA)

7.3 Are the forecast costs of the new CIS system appropriate? (B1-5-1, p. 3)

7.4 What are the appropriate costs for CIS and Customer Care for 2007, including internal and transition costs? (D1-12-1, p. 2 and D3-2-1, p. 1)

As set out below, parties have been able to come to an agreement to settle these issues, as well as other matters related to Customer Care and CIS.

All aspects of this Supplementary Settlement Proposal are subject to approval by the Board. The parties to the settlement all agree that this Supplementary Settlement Proposal is a package: the individual aspects of this agreement are inextricably linked to one another and none of the parts of this settlement are severable. As such, there is no agreement among the parties to settle any aspect of the issues addressed in this Supplementary Settlement Proposal in isolation from the balance of the issues addressed herein. The parties agree, therefore, that in the event that the Board does not accept this Supplementary Settlement Proposal in its entirety, then (in accordance with the Board's Settlement Conference Guidelines) the Board will reject the

Supplementary Settlement Proposal in its entirety and proceed to hearing on all of the issues listed above.

This Supplementary Settlement Proposal, if approved by the Board, will be added to the Settlement Proposal (Ex. N1-1-1) approved by the Board on January 29, 2007 (the "January 29th Settlement Proposal") and the provisions of this Supplementary Settlement Proposal will supersede the references at pages 41 and 42 of the January 29th Settlement Proposal which state that there is no settlement of Issues 7.1 to 7.4.

If approved by the Board, this Supplementary Settlement Proposal will reduce the Company's revenue deficiency for the Test Year by approximately $24.2 million, from the $52.1 million remaining as the revenue deficiency in the Company's Application, after the Settlement Proposal (Ex. N1-1-1) revenue deficiency of $29.9 million was approved by the Board on January 29, 2007 (with $26.0 million thereof recoverable in interim rates effective April 1, 2007). The remaining revenue deficiency at issue in the Company's Application is now about $26.1 million[1], taking into account the fact that parties are agreeing in this Supplementary Settlement Proposal that the Company can recover a revenue deficiency of approximately $1.8 million in respect of customer care and CIS costs in the Test Year.[2] This $1.8 million Customer Care revenue deficiency, which is described below in more detail, is the result of extra costs from customer growth, offset by a reduction in bad debt costs.

Finally, although it is not set out expressly in the sections that follow, the parties agree that, as part of this settlement package, Issue 7.2 is resolved because the Regulatory Asset Account application is no longer necessary. The parties also agree that, in response to Issue 7.1, the Company has filed those materials stipulated in the Board's EB-2005-0001 Decision that are currently available. There are, however, some agreements associated with the Company's move away from CustomerWorks Limited Partnership ("CWLP"), including transition agreements with Accenture Business Services for Utilities ("ABSU")[3], that are not completed. Accordingly, at this time Issue 7.1 is partially resolved and the parties expect that it will be completely resolved when those agreements are finalized and filed.

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[1] Note that this does not include any impact of Supplementary Settlement Proposals related to bill access and IVA charges.

[2] The $1.8 million deficiency to be recovered for Customer Care is derived by starting with the customer care deficiency of $26 million, set out at lines 2 and 3 of the Table at Ex. N1-2-2, p. 2, and then subtracting $24.2 million, which is the agreed-upon revenue deficiency reduction that would result from approval of this Supplementary Settlement Proposal.

[3] For the purposes of this Supplementary Settlement Proposal, both Accenture Business Services for Utilities and Accenture Inc. will be referred to as "ABSU".

With that preamble, the following represents the settlement that has been agreed upon.

II INTRODUCTION

Beginning in 2000, Enbridge Gas Distribution Inc. ("Enbridge Gas Distribution" or the "Company") entered into a series of arrangements whereby CIS and Customer Care services were acquired through a related company, Enbridge Commercial Services Inc. ("ECSI"). ECSI subsequently entered into a limited partnership arrangement with Terasen Inc., CWLP, for the purpose of providing customer related business support and information technology services to utilities. Enbridge Gas Distribution entered into a new Customer Care services agreement with CWLP and consented to ECSI's assignment of its CIS service agreement to CWLP, both effective from January 1, 2002. In August 2002, CWLP entered into an agreement in writing with ABSU, hereinafter referred to as the "Program Agreement", whereby CWLP transferred certain assets and all operating personnel to ABSU, and ABSU agreed to provide Customer Care services, including CIS hosting services, on behalf of CWLP to Enbridge Gas Distribution and other utilities for the period that could be as long as 2002 to 2011 (inclusive) for amounts detailed in a Schedule to the Program Agreement. Since 2002, pursuant to the Program Agreement, ABSU has been performing the Customer Care and CIS services for the Company on behalf of CWLP.

A portion of the fees which the Company has paid to CWLP/ECSI to acquire CIS and Customer Care services was paid by CWLP/ECSI, ultimately, to Enbridge Gas Distribution's parent or other affiliates.

In a series of rate cases, the Intervenors expressed their objection to these arrangements, arguing that ratepayers should only be required to pay for CIS and Customer Care services at a market price or, failing a competitive process, at the cost of any affiliate, or related company, providing the services, including an appropriate return on such an endeavour. In the 2006 rate case decision, the Board agreed that what ABSU was paid to provide the services to Enbridge Gas Distribution for Customer Care and CIS services was relevant to the determination of the market prices for the services. The Board ultimately used CWLP revenue from Enbridge Gas Distribution, expressed as a proportion of CWLP's total revenues, as a tool to derive CWLP overearnings attributable to Enbridge Gas Distribution, and then, using the utility allowed return, the Board determined the amount recoverable from Enbridge Gas Distribution's ratepayers. The Board, in decisions in rate cases beginning in 2003 and culminating in Enbridge Gas Distribution's 2006 rates case, urged the Company to obtain CIS and Customer Care services by direct competitive tender which, in the Board's view, should exclude the right of first refusal in favour of CWLP.

Following the Decision with Reasons of the Board in EB-2005-0001, Enbridge Gas Distribution undertook to do the following:

1. Acquire a new Customer Information System (CIS) through a direct competitive tender;

2. Acquire Customer Care services through a direct competitive tender.

Enbridge Gas Distribution also convened a consultative process (the "Consultative") through which Intervenors could monitor and comment on these procurement processes. In light of the concern which Intervenors had, in past rate cases, expressed about Enbridge Gas Distribution's arrangements for acquiring CIS and Customer Care Services, the Intervenors wanted to be assured that the procurement processes were consistent, in all respects, with accepted industry standards, and that the arrangements resulting from the procurement processes will not result in amounts being paid by Enbridge Gas Distribution to CWLP, Enbridge Gas Distribution's affiliates, or its parent. Enbridge Gas Distribution convened the Consultative in part to give the Intervenors those assurances. To further ensure that the Consultative could achieve its goals, Intervenors were given access to independent expertise to advise them on the procurement processes and the results therefrom.

Through the Consultative, the Company informed Intervenors that CWLP has not indicated any intention to exercise its right of first refusal in respect of the new Customer Care or CIS services. CWLP/ABSU have now committed to include a clause in the transition agreements associated with the move to new service providers that will waive CWLP's right of first refusal when the transition agreements are signed.

The Company represents that, apart from the payments to be made by the Company to CWLP up to April 1, 2007, no more than $8.34 million in aggregate will be paid by any person to CWLP, ECSI, EI or any other related entity in relation to any Customer Care or CIS services included within this agreement and provided to Enbridge Gas Distribution by any person during the course of this agreement.

As a result of the work of the Consultative, Enbridge Gas Distribution and the Intervenors have been able to reach agreement on certain aspects of the procurement processes completed to date. The work of the Consultative is described in the pre-filed evidence of Mario Bauer, filed as Exhibit L-2.

The procurement processes will not be completed, with the selection of a new CIS and a new Customer Care service provider, until mid 2007. As a result, the cost of the new CIS and of the new Customer Care service provider cannot be estimated at this time. In addition, the prudence and cost consequences of the CIS and Customer Care arrangements cannot be determined until those arrangements have been finalized, which is expected to be in the first half of 2007. As well, the new CIS will not become operational until June 2009 and it is only at that time that final costs for the new CIS will be known. Finally, the shortlisted bidders for Customer Care services include ABSU and a third party, so there is the potential that a new service provider, other than ABSU, will be selected. The introduction of a Customer Care service provider, other than ABSU, will involve transition arrangements with ABSU and others in both 2007 and 2008, and the costs consequences and upper limits of those costs have been estimated. Final estimates of such costs cannot be made until a later date.

Within these practical constraints, the parties have settled Issues 7.1 through 7.4, which are the Customer Care and CIS issues in this EB-2006-0034 proceeding. The settlement necessarily reflects the fact that certain aspects of the CIS and Customer Care arrangements, including the final costs and contract terms, will not be known until later in 2007.

The parties have agreed that a placeholder amount will be used to establish the revenue requirement for Customer Care costs for 2007. The placeholder chosen is the cost-per-customer set by the Board in the EB-2005-0001 Decision, at $49.58. As a result of this settlement, the total Customer Care budget to be recovered in rates for 2007, including all internal and external costs (except for bad debt), and including all revenue requirement impacts of CIS, will be $90.8 million, plus an amount of $15.1 million representing the provision for uncollectible accounts.

The settlement includes provision for a “true-up” process to adjust the revenue requirement to reflect the prudent and reasonable forecast amounts resulting from the procurement processes, and to reflect the agreed-upon recovery of certain “transition” costs.

The parties believe that a six-year term, covering the period 2007 through 2012 inclusive, is the appropriate term over which to calculate the revenue requirement relating to Customer Care and CIS. The expected costs of CIS and Customer Care during that period may fluctuate year over year. The parties agree that the annual amounts included in rates should be smoothed, over the 2007-2012 term, to avoid swings in rates. The effect of the true-up process is (a) to capture any variance between the 2007 placeholder for Customer Care and CIS revenue requirement of $90.8 million and the normalized revenue requirement for 2007 and pay that variance to, or recover it from, the ratepayers in the 2008-2012 period, and (b) establish the component of the Company’s revenue requirement relating to Customer Care and CIS (except bad debt) for the period 2007-2012, and smooth the rate impacts of that component over that period.

To reflect the settlement the parties have agreed upon a template (the “Template”), which sets out all of the relevant categories of expenses over the 2007 to 2012 period that relate to Customer Care and CIS (except for bad debt costs). The costs in a number of those categories can be established today, and the parties have therefore agreed to those amounts. However, some costs to be set out in the Template must be determined when the contract prices and other costs are known. For those costs, the parties have agreed to the parameters under which those costs will be calculated or forecast and then included in the true-up calculation.

As the parties anticipate the possibility of an incentive regulation ("IR") regime, the terms of which are expected to be established later in 2007, they believe that the true-up should occur at a time when the IR formula for the Company has been established. Once the contract for Customer Care services has been signed, and the terms of IR are known, which is expected to be in the fall of 2007, the parties have agreed that the true-up should take place, in accordance with the true-up rules set out in this Settlement Proposal and Appendix. Parties agree that adjustments may need to be made to aspects of this agreement in the event that the IR regime that, for the purposes of calculation, was assumed by the parties in creating the Template – ie. a price cap IR regime of five years in duration, beginning January 1, 2008 - is not established. Adjustments may need to be made to the normalization approach set out in the True-Up Rules (which are attached) to make it compatible with the IR model and formula that is approved for Enbridge Gas Distribution. Any such adjustments would not affect the total revenue requirement to be recovered over the term of this agreement, but they may impact upon the amount to be recovered in each year of the agreement under the normalization approach that is used.

Finally, the parties agree that the Consultative will continue to monitor the completion of the procurement process, up to and including reviewing the final terms of the contracts, and thereafter, the implementation of the CIS and Customer Care arrangements, which the parties agree will be no later than six months after the in-service date for the new CIS. As has been the case to date, the Intervenors involved in the Consultative agree that they will raise any concerns about the ongoing process, and the outcomes from that process, as soon as they have sufficient information to identify and communicate those concerns. If the Intervenors involved in the Consultative believe that they are not receiving sufficient information, they will advise the Company immediately. The parties agree that the Consultative will continue to work in a timely, responsive and reasonable manner until its mandate is completed. Finally, the parties agree that all costs of the Consultative, for as long as it continues, will be fully recoverable from ratepayers. Costs of the Consultative that are incurred in 2007 will be included in the already established 2007 Ontario Hearings Costs Variance Account (2007 OHCVA). Parties agree to support the continuation of appropriate deferral accounts in future years for the recording and disposition of future costs of the Consultative, unless these costs are included in the Company's regulatory O&M budget during the IR term.

II TERMS OF SETTLEMENT

Against that background, the parties have agreed as follows:

(A) 2007 O&M Customer Care costs

As noted above, certain of the anticipated costs associated with Customer Care during the period 2007 through 2012 will not be known until RFP processes currently being carried out by the Company are completed and market prices are identified. As a result, revenue requirement will be established for 2007 using a placeholder to calculate the Customer Care costs. The placeholder will be the Board-approved 2006 cost per customer of $49.58, times the projected number of customers in 2007, 1,831,283, to get a total Customer Care placeholder of $90.8 million for 2007.

The parties agree that projected bad debt costs (Provision for Uncollectible Accounts) of $15.1 million as filed by the Company shall be recoverable in rates in 2007. This agreement does not deal with bad debt costs beyond 2007; as a result, bad debt costs are not included in the True-Up calculation. For the period from 2008 to 2012, bad debt costs will be dealt with by the Board along with other O&M costs, separately from other Customer Care costs which are the subject of this agreement, in such other proceeding or proceedings as the Board may determine.

For the purposes of settlement, the Customer Care placeholder of $90.8 million plus bad debt costs of $15.1 million will replace the amounts in the Company's Application and pre-filed evidence which total $130.1 million, and are comprised of $101.6 million for Customer Care and CIS Service Charges, $3.4 million for Customer Care Internal Costs, $15.1 million for Provision for Uncollectibles and $10.0 million for transition costs (see Exhibit D1-2-1, p. 3, Table 1, lines 2 to 4 and Ex. D1-1-1, p. 1, Table 1, line 3). These internal and transition costs are addressed in the True-Up Rules which are attached as Appendix A.

As a result, the settlement of this item will reduce the Company's revenue deficiency for the Test Year by approximately $24.2 million, from the $52.1 million remaining as the revenue deficiency in the Company's Application, after the Settlement Proposal (Ex. N1-1-1) revenue deficiency of $29.9 million was approved by the Board on January 29, 2007 (with $26.0 million thereof recoverable in interim rates effective April 1, 2007). The remaining revenue deficiency at issue in the Company's Application is now about $26.1 million, taking into account the fact that parties are agreeing in this Supplementary Settlement Proposal that the Company can recover a revenue deficiency of approximately $1.8 million in respect of customer care and CIS costs in the Test Year (the amount that is the difference between the 2006 Board-approved budget of $104.1 million and the $105.9 million total amount for 2007 for Customer Care, CIS and bad debt costs). This $1.8 million Customer Care revenue deficiency can be derived by accounting for customer growth in F2007 over the previous year (the $49.58 placeholder is multiplied by 46,228, which is the forecast number of new customers in 2007) and adjusting for a reduction of $500,000 in bad debt costs, as compared to F2006.

(B) <u>2007 Capital costs related to CIS</u>

The parties agree that any capital spending by the Company during the 2007 Test Year related to the new CIS shall be in addition to the Company's overall Board-approved capital budget of $300 million plus the costs of the Portlands Energy Centre LTC. This is consistent with the language in Issue 1.1 of the Settlement Proposal in this EB-2006-0034 proceeding, which was approved by the Board on January 29, 2007 and which stated that "[p]arties have reached a global settlement of all 2007 Rate Base issues, except for issues related to the capital budget for the new CIS system" (Ex. N1-1-1, p. 13). No capital expenditures in 2007 relating to the new CIS will be closed to rate base in 2007, and the new CIS will have no impact on 2007 rates.

(C) <u>Selection process for new CIS and Customer Care service providers and Transition Plan</u>

As explained above in the Introduction section, it is anticipated that the selection of a new CIS and a new Customer Care service provider will occur in the second quarter of 2007, when the associated RFP processes are completed.

Once selections are made, contracts will have to be negotiated and settled with the chosen parties. At that time, some of the expected costs of the new CIS, and payments to be made to the new Customer Care service provider, will be established between Enbridge Gas Distribution and the service providers through contractual arrangements. The Consultative will continue to function until the completion of the procurement process, the implementation of those CIS and Customer Care arrangements and the completion of the true-up process described below. The Consultative will be involved with monitoring the selection process and reviewing the terms and prudence of the resulting contracts, including the reasonableness of their costs. Parties agree that the Consultative will continue to work in a timely, responsive and reasonable manner until its mandate is completed.

The selection processes for both the CIS and the Customer Care services RFPs are underway. At this point, the remaining shortlisted bidders for the Customer Care services include ABSU and a third party. The remaining shortlisted bidders for the system integrator component of the new CIS include ABSU and a third party. The parties have agreed that for the time period from January 1, 2007 to March 31, 2007, CWLP will continue to provide CIS and Customer Care services to Enbridge Gas Distribution. For the period commencing April 1, 2007 and concluding no later than September 30, 2008, Enbridge Gas Distribution is making arrangements with ABSU to provide the CIS and Customer Care services directly to Enbridge Gas Distribution, at least until the potential transition to new service providers is complete.

There are two types of transition costs addressed in this Supplementary Settlement Proposal: CIS transition costs and Customer Care transition costs.

The parties acknowledge and agree that all transition costs with respect to the new CIS are included in the $118.7 million capital cost of the new CIS (discussed below), whether or not ABSU is awarded the system integrator component of that project.

The parties further acknowledge and agree that, in the event that ABSU is chosen as the Customer Care service provider, there will be no transition costs associated with Customer Care services. In the event that the third party is chosen as the Customer Care service provider, then there will be transition costs associated with the move to the new service provider. Enbridge Gas Distribution has prepared, and has shared with the Consultative, a Transition Plan that sets out how Customer Care may be transitioned to a new service provider. The parties agree that there will be costs associated with any such transition, and that those costs are recoverable in the manner and amounts described in detail in the True-Up Rules at Appendix A. The Company agrees that it will keep the transition costs, and the transition time period, to a reasonable level while managing the risks associated with transition and ensuring that the ongoing provision of Customer Care services meets OEB-mandated service levels. In this regard, the Company agrees that while the maximum time period for transition to a new Customer Care service provider will be 18 months from April 1, 2007, it will make best efforts to shorten that time period. The Company will ensure that its arrangements with ABSU will allow the Company to direct ABSU to cease the provision of some or all Customer Care transition services before the end of 18 months and, as a result, to reduce the transition costs payable by Enbridge Gas Distribution to ABSU.

(D) <u>The True-Up process and Revenue Requirement for 2008 to 2012</u>

(i) Overview

The parties agree that, on a date (the "True-Up Time") that is the later of (a) the date when the Company's Customer Care RFP is completed and the contract is signed, and

(b) the date when the Board's decision with respect to the duration, rules and formulae for IR that relate to Enbridge Gas Distribution is released, the parties will calculate a true-up and smoothing for the Customer Care amounts for 2007 to 2012, using the specific rules set forth in Appendix A to this Settlement Proposal (the "True-Up Rules").

As set out in more detail below in Appendix A, the amount of the Customer Care costs that are projected to be incurred by the Company during the 2007 to 2012 period, and which the Company will recover in rates, will be determined by the parties at the True-Up Time in accordance with the criteria specified in the True-Up Rules. The components of the Customer Care costs and revenue requirement are itemized in the "Customer Care and CIS Settlement Template" (already defined as the "Template"), which is attached to Appendix A.

It is the intention of the parties that the True-Up process will be used to determine the Customer Care amount for 2007 (the "Normalized 2007 Customer Care Revenue Requirement") that, when adjusted using the True-Up Rules for each year until 2012, will allow the Company to fully recover in rates the costs incurred in providing Customer Care services (including CIS) during the period from 2007 through 2012.

In the event that the parties are unable to agree on the amount of any component of the Normalized 2007 Customer Care Revenue Requirement or any number to be included in the Template, other than those numbers that are fixed by the terms of this agreement, then parties agree that the unresolved dispute will be determined by the Board in accordance with the criteria specified in the True-Up Rules. Specifically, if the parties have not agreed to the Normalized 2007 Customer Care Revenue Requirement within sixty days of the True-Up Time, they shall list the components of the calculation that are in dispute, and provide that list to the Board for determination in accordance with the criteria specified in the True-Up Rules.

The outcome of the True-Up process will be the subject of a separate application to the Board. That application will include, for Board approval, all numbers that are agreed upon and set in accordance with the True-Up Rules, as well as the list of the items remaining at issue to be determined by the Board.

(ii) 2007 Customer Care Variance Account

At True-Up Time, the Company will calculate the difference (the "2007 Customer Care Revenue Requirement Variance") between that amount of revenue requirement that is, pursuant to the True-Up Rules, recoverable for 2007 Customer Care costs (the Normalized 2007 Customer Care Revenue Requirement) and the placeholder of $90.8 million, and will credit or debit the 2007 Customer Care Revenue Requirement

Variance, as the case may be, to the 2007 Customer Care Variance Account. The balance in that account will be repaid to the ratepayers, or charged to the ratepayers, with interest, over the course of 2008 to 2012. The 2007 Customer Care Variance Account will be cleared in accordance with the True-Up Rules.

In order for effect to be given to this provision of this Settlement Proposal, parties agree that it is appropriate that a 2007 Customer Care Variance Account be created, and continued until 2012.

(iii) Revenue requirement for Customer Care costs between 2008 and 2012

The revenue requirement that the Company will be entitled to recover each year in respect of Customer Care costs (including CIS but not including bad debt) from 2008 to 2012 shall be the Normalized 2007 Customer Care Revenue Requirement, as adjusted for each year from 2008 to 2012 (inclusive) by the Incentive Regulation formula. The intention of the parties is that this will result in a relatively stable revenue requirement for CIS and Customer Care services over a five year period.

As set out above, and explained in the True-Up Rules, the "Normalized 2007 Customer Care Revenue Requirement" will be the amount that, when adjusted according to the True-Up Rules (including the rules for IR described as part of the True-Up Rules) for each year until 2012, will allow the Company to fully recover in rates the total of all forecast prudent and reasonable Customer Care costs (including CIS but not including bad debt) for the period from 2007 through 2012.

The parties agree that all O&M costs associated with Customer Care (except for bad debt costs), including O&M relating to the Company's proposed new CIS, are included in the calculation of Normalized 2007 Customer Care Revenue Requirement and therefore will be properly recovered in rates during the period 2007 through 2012 through the operation of the True-Up Rules.

The Company agrees that, once the outstanding items on the Template are determined, and completed, and, as a result, the Normalized 2007 Customer Care Revenue Requirement is established, the Company will not seek any adjustment to its rates or revenue requirement that is directly or indirectly based on changes in Customer Care costs during the term of this agreement. Intervenors similarly agree that they will not seek adjustments to the Company's rates or revenue requirement that is directly or indirectly based on changes in Customer Care costs. As expressed above, bad debt costs are not included as part of the Customer Care costs that are the subject of this agreement from 2008 to 2012.

Notwithstanding the limitations expressed in the preceding paragraph, the parties agree that in the event that new legislative or regulatory requirements, that are currently unknown and that are beyond the Company's control, are imposed on the Company, in the period up to and including 2012, and those requirements materially change the level of Customer Care costs, then any of the parties shall be entitled to make application to the Board for adjustments to rates or revenue requirement as appropriate. The materiality threshold that applies to this aspect of the agreement will be established at the IR proceeding. The parties agree that the rights conferred in this paragraph will be no greater than any rights to revisit any issue based on changes in legislative or regulatory requirements that are established as part of the IR rules that apply to the Company.

In order to give effect to certain aspects of the True-Up Rules, as detailed in Appendix A, parties agree that it is appropriate that 2007 and 2008 Customer Care Transition Costs Variance Accounts be created to track certain transition costs related to Customer Care. The transition costs to be tracked in these accounts relate to activities that ABSU and external contractors and internal resources will undertake to transfer knowledge and services to the new service provider. This will include such tasks as training, documentation and management of the vendors through the transition. The transition costs to be tracked in these accounts are subject to a maximum total amount of $11.1 million. The details of the 2007 and 2008 Customer Care Transition Costs Variance Accounts are set out below, as part of the True-Up Rules.

(iv) New CIS

As the Board is aware, the Company is planning to replace its current CIS service with a new CIS that will be owned by the Company. When this system is implemented, which is expected in 2009, its capital cost will be included as part of the Company's utility rate base. Through the Consultative process, and subject to an adjustment described below, the parties have agreed that a reasonable cost for this asset is $118.7 million, including procurement costs of $5.1 million. The parties agree that rates will be set during the period of this agreement on the basis of a CIS cost that will be no higher than $118.7 million. This $118.7 million budget consists of an amount of $42 million for system integrator contract costs, which are subject to a direct competitive tender process, and an amount of about $76.7 million which the Company will manage and control during the CIS procurement and implementation process.

All parties agree that the Company's revenue requirement associated with Customer Care activities for the 2007 to 2012 period will incorporate a portion of the cost for the new CIS of $118.7 million, including procurement costs of $5.1 million, as set out below. The procurement process that provides support for the reasonableness of this cost is described in the evidence of Mario Bauer (Exhibit L-2), and the CIS cost analysis attached thereto. The parties agree that this $118.7 million cost is subject to reduction in the event that the system integrator contract costs arrived at through the CIS procurement process are less than $42 million. In the event that the system integrator costs are $42 million or more, then the parties agree to the cost of $118.7 million for the completion of the Template and the term of this agreement.

While the revenue requirement attributable to CIS shown in Row 3 of the Template is not yet finalized, the parties agree upon the following:

1. As stated above, the parties agree upon the prudence of the CIS procurement process and the capital cost for the new CIS of $118.7 million, which includes procurement costs of $5.1 million.

2. The parties agree that the amounts to be recovered in rates will be reduced, if the system integrator contract costs arrived at through the CIS procurement process are less than $42 million.

3. Subject to the restrictions on CIS costs set forth in this agreement, there is agreement that all prudently incurred and reasonable costs associated with the new CIS, including return and income taxes, should be recoverable in rates, during the term of this agreement, and for the 10-year economic life of the new CIS assets.

4. The parties agree that the term of this agreement will be six years from 2007 to 2012, in order to enable the smoothing and managing of the recovery of the revenue requirement attributable to the new CIS during those years.

5. The parties agree that they support the decision to procure the new CIS as prudent, the inclusion of the new CIS in rate base in 2009, and the recovery of all amounts associated with the new CIS subject to the terms of this agreement. Subject to any adjustment that may be made to rate base as of December 31, 2012 to reflect the actual costs of the new CIS, as set forth below, the parties agree that, as of January 1, 2013, the amount included in opening rate base for the new CIS shall be its 2012 closing net book value of approximately $71.4 million.

6. The parties agree that, for rate-making purposes, the in-service date of the new CIS will be deemed to be July 1, 2009, regardless of the actual in-service date, and the rate base for the new CIS will be calculated in all respects as if it was brought into service on July 1, 2009.

7. The parties agree that, for rate-making purposes, CIS Capital Costs at the end of the term of this Agreement will be treated as follows:

   a. If the actual costs of the New CIS are less than $118.7 million, then the $71.4 million amount included in the January 1, 2013 opening rate base for the New CIS shall be appropriately adjusted downwards;

   b. No capital costs in addition to the amount of $118.7 million will be eligible for closure to rate base on January 1, 2013, unless Enbridge Gas Distribution then demonstrates the reasonableness and prudence of such additional costs; and on the further condition that the only additional amounts eligible for consideration will be confined to increases in the system integrator costs beyond the $42 million provision for those costs included within the budget of $118.7 million.

On this basis, and subject to later adjustment as described at point 2 above, the parties request the Board, as part of the approval of this Settlement Proposal, to approve the prudence and $118.7 million cost of the new CIS, which includes procurement costs of $5.1 million.

The parties agree that there are three, and only three, possible adjustments to be made later to the revenue requirement attributable to CIS for the period 2009 through 2012, as shown in Row 3 of the Template.

The first possible adjustment relates to the tax savings associated with the high Capital Cost Allowance (CCA) for IT hardware and software for the CIS asset. The high CCA produces substantial tax savings in the first two years of the asset's ten year life. The Company acknowledges and agrees that the ratepayers are to receive credit for the full value of these tax savings. The tax rules provide that Enbridge Gas Distribution will be kept whole with respect to income taxes over the full economic life of utility assets, including the 10-year life of the CIS assets. Parties disagree over when the tax savings should be reflected in revenue requirement and rates.

To support a settlement, the parties agree, for ratemaking purposes, to the use of the values included in Row 3 of the Template in determining the revenue requirement for use at True-Up Time. Those values are calculated as if the CIS costs, including tax savings, were calculated on a conventional forward test year cost of service basis for each year during the period 2009-2012. The Company has agreed to use this assumption on the understanding that Enbridge Gas Distribution retains the right to bring an application before the Board seeking a different approach to the timing of when the tax savings are reflected in revenue requirement. Enbridge Gas Distribution agrees that it will, if it elects to make such application, file that application by June 30, 2007. Intervenors' rights to oppose any such application remain unfettered and they retain the right to rely on any and all grounds of opposition considered by them to be appropriate. The parties agree that there will be no inference that Enbridge Gas Distribution has tacitly acquiesced to values in Row 3, by accepting them in this Supplementary Settlement Agreement, and all parties acknowledge that the Company's acceptance of the values in Row 3 is "without prejudice" to the application described above, should the Company decide to file it by June 30, 2007. In the event that the Board approves a different approach to the timing of when the tax savings are reflected in revenue requirement, then parties agree that the values shown in Row 3 of the Template are to be adjusted accordingly. If Enbridge Gas Distribution does not file such an application by June 30, 2007, or if Enbridge Gas Distribution files such an application but the relief requested is not granted, then, subject to the remaining possible adjustments described below, the values in Row 3 of the Template will remain as stated therein.

The two remaining potential adjustments to the CIS revenue requirement amounts for the period 2009 through 2012, as shown in Row 3 of the Template, pertain to Enbridge Gas Distribution's equity ratio and the possibility that the system integrator contract costs resulting from the CIS procurement process are less than $42 million.

The amounts in Row 3 of the Template reflect a 35% level of deemed equity for the Company. The issue of the appropriate level of deemed equity for the Company is currently before the Board in this F2007 rate case, and there may be changes from the 35% level. Parties agree that the amounts in Row 3 of the Template should be adjusted at True-Up Time in the event that the Company's level of deemed equity is changed in the Board's decision in the F2007 rate case.

The amounts in Row 3 of the Template reflect a $118.7 million cost for the new CIS. In the event that the system integrator contract costs arrived at through the CIS RFP process are less than $42 million, then parties agree that the amounts in Row 3 should be adjusted accordingly. In the event that the system integrator costs are $42 million or more, then the parties agree to the cost of $118.7 million for the term of this agreement.

Subject to the outcome of any application which Enbridge Gas Distribution may bring before the Board, as described above, Enbridge Gas Distribution agrees that once the outstanding items on the Template are determined, and completed, and as a result the Normalized 2008 Customer Care Revenue Requirement is established, the Company will not seek any adjustment to its rates or revenue requirement relating to the cost of the new CIS during the term of this agreement. Intervenors similarly agree that they will not seek adjustments to the Company's rates or revenue requirement that are directly or indirectly based on changes in CIS costs.

Notwithstanding the limitations expressed in the preceding paragraphs, the parties agree that in the event that new legislative or regulatory requirements, that are currently unknown and that are beyond the Company's control, are imposed on the Company, in the period up to and including 2012, and those requirements materially change the level of CIS costs, then any of the parties shall be entitled to make application to the Board for adjustments to rates or revenue requirement as appropriate. The materiality threshold that applies to this aspect of the agreement will be established at the IR proceeding. The parties agree that the rights conferred in this paragraph will be no greater than any rights to revisit any issue based on changes in legislative or regulatory requirements that are established as part of the IR rules that apply to the Company.

(v) Future revenue-generating opportunities from the new CIS

The Company agrees to use its best efforts to identify and take advantage of opportunities to use the new CIS asset to provide CIS services to third party organizations to generate additional revenue opportunities, and that the gains from any such opportunities shall be shared with ratepayers in a manner to be agreed upon. A consultative group, including Intervenors, may be convened to consider how such opportunities would be addressed. The parties agree that, in the event that the sharing of such gains cannot be agreed upon by the parties, then they will put the issue of the appropriate gainsharing to be used to the Board. The parties agree that any gains to be shared with ratepayers would be cleared to ratepayers by way of an annual adjustment to delivery rates.

Billing services on the Enbridge Gas Distribution bill are covered by the Supplementary Settlement Proposal related to open bill access (Ex. N1-1-1, Appendix C), and are not included in or affected by the provisions set out above.

APPENDIX A – TRUE-UP RULES

Attached to this Appendix A is a document entitled "Customer Care and CIS Settlement Template" (the "Template"). The parties have completed each of the boxes A1 through G17 of the Template, by inserting a dollar amount, or zero, or a TBD (To Be Determined) which will be completed at the True-Up Time. The following rules apply to the completion of the Template:

1) Where in the Template there is a dollar figure or zero already inserted in any box, that figure is agreed by the parties, and subject to paragraphs 3, 4 and 6 below, will not be altered.

2) The figures agreed to by the parties which are fixed and not subject to change, and which are already included in certain boxes within the Template, include the following:

    a. Rows 1, 2 and 2a: rows 1 and 2 represent the amounts that parties agree can be recovered in rates related to payments by Enbridge Gas Distribution to ABSU to provide CIS services and the payments by ABSU to ECSI for the use of the existing CIS asset, until the new CIS asset is in service. Row 2a represents the amounts to be paid to CWLP for the use of the CIS asset from January 1, 2007 to March 31, 2007. Parties agree that a total of $28.9 million shall be included on these rows, divided into the individual amounts included in the Template.

    b. Row 4: parties agree to the figures included in the Template as the amounts to be paid for the hosting and support of the new CIS. These amounts are based on Enbridge Gas Distribution estimates which the Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

    c. Row 5: parties agree to the figures included in the Template as the amounts to be recovered for the Company's backoffice costs (excluding bad debt) associated with both the old and the new CIS. These amounts are based on Enbridge Gas Distribution estimates which the Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

    d. Rows 6 and 7: SAP has been chosen as the provider for the software that will support the new CIS. This software may require some modifications or adaptations, from time to time, to fully support the CIS. The parties agree to the figures included rows 6 and 7 of the Template as the amounts to be paid to SAP for licence fees and for modifications that may be necessary. These amounts are based on Enbridge Gas Distribution estimates which the Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

e. Row 8: box 8A includes the amount of $16.9 million, which is the amount that parties have agreed can be recovered in rates related to the provision of Customer Care services by CWLP for the period from January 1, 2007 to March 31, 2007 (which is the date on which ABSU will begin providing Customer Care services on a temporary or permanent basis). Given that CWLP will stop providing services to Enbridge Gas Distribution as of April 2007, the amounts to be reflected in boxes 8B, 8C, 8D, 8E and 8F are zero.

f. Row 11: parties agree to the figures included in the Template as the amounts to be recovered for Customer Care licences to support the existing and new Customer Care service provider delivery of Collections, E-Billing and text to speech voice capability functions. These amounts are based on Enbridge Gas Distribution estimates which Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

g. Row 12: parties agree to the figures included in the Template as the amounts to be recovered for the Company's backoffice costs (excluding bad debt) associated with Customer Care services. These amounts are based on Enbridge Gas Distribution estimates which Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

h. Row 13: this row includes the costs incurred by the Company, and accepted for recovery from ratepayers, related to the procurement of a new customer care service provider. The parties have agreed that a total amount of $4.9 million may be recovered at row 13. This total amount represents the internal and external procurement costs for the new Customer Care services that have been determined by the parties to be prudently incurred and reasonable for recovery from ratepayers. This total amount is allocated equally over the five years from 2008 to 2012. Thus, the amount of $0.98 million is inserted in each of the boxes A13 to F13.

i. Row 17: the total number of customers for each year.

3) Row 3 includes the revenue requirement associated with the new CIS for each of the years from 2007 to 2012, to be filled in as follows:

a. The amounts in boxes A3 and B3 shall be zero, since there is no revenue requirement associated with the new CIS until 2009.

b. The amounts in boxes C3, D3, E3 and F3 represent the annual revenue requirement associated with each of 2009, 2010, 2011 and 2012 for the new CIS. These amounts, which total $46.210 million, are based upon the agreed-upon cost of the new CIS of $118.7 million. The derivation of these amounts is set out in the spreadsheets attached as Appendix B and the total of $46.210 million is the sum of the items in Columns 1, 2, 3 and 4 at line 12 on the first page of Appendix B. These amounts are subject to adjustment as follows:

   i. the amounts in row 3 of the Template reflect a $118.7 million cost for the new CIS. In the event that the system integrator contract costs arrived at through the CIS RFP process are less than $42 and the overall cost is therefore reduced, then parties agree that the amounts in row 3 should be changed to correspond to the lower new CIS cost;

   ii. the amounts in row 3 of the Template reflect a 35% level of deemed equity for the Company. The issue of the appropriate level of deemed equity for the Company is currently before the Board in this F2007 rate case, and there may be changes from the 35% level. Parties agree that the amounts in row 3 of the Template should be changed in the event that the Company's level of deemed equity is changed;

   iii. In the event that the Company is successful in an application to the Board for a different approach to the timing of when tax savings associated with the new CIS are reflected in revenue requirement, then corresponding changes will be made to the amounts in row 3.

4) The amounts to be inserted in boxes A9 and B9 shall be determined by the parties as the prudent and reasonable amounts for recovery from ratepayers for sums paid or forecast to be payable by the Company to ABSU for Customer Care services during the period April 1, 2007 through September 30, 2008, in accordance with the following criteria:

   a. In the event that ABSU is chosen as the new service provider for Customer Care services from and after April 1, 2007 until December 31, 2012, then the figures to be inserted in boxes A9 and B9 are zero, because there will be no need for a transition period to a new service provider;

b. In the event that a third party other than ABSU is chosen as the new service provider for Customer Care services, then there will be the need for a transition period, for a maximum of 18 months from April 1, 2007, during which ABSU will provide Customer Care services until the new service provider can be fully phased-in.

c. The Company has reached agreement with ABSU for Customer Care services to be provided, on a transition basis for 2007 and 2008 in the event that ABSU is not the successful Customer Care bidder. For settlement purposes, subject to subparagraph (d) below, the Parties agree that amounts of up to $52,263,000 for 2007 and $42,623,000 for 2008 will be included in boxes A9 and B9. These numbers represent the maximum agreed-upon level of costs that the Company may recover in rates in respect of the amounts charged by ABSU during 2007 and 2008 for Customer Care services, on a transitional basis, based on a recoverable cost of $38 per customer per year and a transition period of 18 months;

d. The Company will make best efforts to reduce the length of the transition period from 18 months, and to reduce the actual forecast costs per customer from ABSU to be less than currently forecast. In the event that the actual costs to date and updated forecast costs from ABSU at True-up Time for Customer Care services for the transition period are less than $52,263,000 for 2007 or $42,623,000 for 2008, then the numbers to be inserted in boxes A9 and B9 will be the actual costs to date and updated forecast costs at True-Up Time.

e. The amounts to be inserted in boxes C9, D9, E9 and F9 are zero because, in any event, the transition period for customer care services will not extend beyond 2008.

5) The amounts to be inserted in boxes A10 to F10 are the reasonable forecast annual costs of the new Customer Care service provider, to be determined at the True-Up Time through the results of the Customer Care procurement process. In the event that ABSU is chosen as the new service provider, it is expected that these amounts will be effective as of April 1, 2007. In the event that a third party other than ABSU is chosen as the new service provider, it is expected that these amounts will begin at some time in 2007 or 2008, because of the need for transition time and activities. The amounts to be included in these boxes are subject to review by the Consultative for prudence and reasonableness. In the event that the Intervenors and the Company do not agree, the issue of prudence and reasonableness will be determined by the Board.

6) The amounts at rows 14 and 15 represent the transition costs associated with moving from CWLP as the Customer Care service provider to a different third party service provider. The transition costs to be included in these rows, and tracked in the 2007 and 2008 Customer Care Transition Costs Variance Accounts, relate to activities that ABSU and external contractors and internal resources will undertake to transfer knowledge and services to the new service provider. This will include such tasks as training, documentation and management of the vendors through the transition.

    a. In any event, the number in boxes A14/A15 will be zero.

    b. In the event that ABSU is chosen as the new Customer Care service provider then the amounts to be inserted in boxes B14 to F14 and B15 to F15 are zero and subparagraphs 6(c) to (f) do not apply.

    c. In the event that a different third party is chosen as the new Customer Care service provider, then a total amount of $11.1 million will be included on rows 14 and 15. This total amount will be split equally between the years 2008 to 2012, in the amount of $2.22 million per year. Thus, each of boxes B14/B15, C14/C15, D14/D15, E14/E15 and F14/F15 will include the number $2.22 million.

    d. The Company will record all prudent and reasonable amounts spent for services, both internal and external, to facilitate the transition from CWLP/ABSU providing Customer Care services to a new service provider in the 2007 and 2008 Customer Care Transition Costs Variance Accounts, to a total maximum of $11.1 million. It is agreed that amounts paid for internal costs shall not include the costs of employees or other resources already included in the budget for the year and re-assigned to this transition, unless a specific new resource was acquired to backfill those other functions.

    e. Commencing in 2008, and continuing each year until 2012, the Company will expense the amount of $2.22 million for Customer Care costs, and will at the same time, deduct the same amount from the total amounts recorded in the 2007 and 2008 Customer Care Transition Costs Variance Accounts. The parties agree that, even if the outstanding balance in the 2007 and 2008 Customer Care Transition Costs Variance Accounts becomes zero before 2012, the Company is still entitled to expense and recover the amount of $2.22 million for each year until 2012. The parties further agree that no negative balances will be reflected in the 2007 and 2008 Customer Care Transition Costs Variance Accounts.

f. Parties agree that if the total amounts recorded in the 2007 and 2008 Customer Care Transition Costs Variance Accounts are less than $11.1 million as of December 31, 2008, then the difference between $11.1 million and the total amounts recorded in the 2007 and 2008 Customer Care Transition Costs Variance Accounts will be credited to ratepayers with interest in equal amounts in 2009 to 2012.

7) Row 16 will be the totals of each of the columns, to be completed when all of the above figures are determined.

8) Column G will be the totals of each of the rows, to be completed when all of the above figures are determined.

9) Box G16 will be the total of all Customer Care costs and revenue requirement forecast for the period (the "Total Customer Care Forecast").

10) Box G17, already completed, is the forecast total of annual numbers of customers during the period (the "Customer Count").

At True-Up Time, once the Template has been completed, then the Normalized 2007 Customer Care Revenue Requirement can be determined. This will be calculated by starting with the Total Customer Care Revenue Requirement for 2007 to 2012, which is the sum of boxes A16 to F16. That Total Customer Care Revenue Requirement will then be placed into an amortization model that calculates, using the IR annual adjustment that is approved for Enbridge Gas Distribution, the Normalized 2007 Customer Care Revenue Requirement which is the number that, when adjusted for IR annual adjustment for each year from 2008 through 2012, would allow the Company to fully recover the Adjusted Customer Care Revenue Requirement for 2007 to 2012.

At the same time, parties will calculate the 2007 Customer Care Revenue Requirement Variance by taking the difference between the Normalized 2007 Customer Care Revenue Requirement and the placeholder of $90.8 million. The Company will credit or debit the 2007 Customer Care Revenue Requirement Variance, as the case may be, to the 2007 Customer Care Variance Account. The balance in that account will be repaid to the ratepayers, or charged to the ratepayers, with interest, over the course of 2008 to 2012.

Attached to this Appendix A is an illustrative example of how the True-Up will be applied. For the purpose of this example, the following assumptions have been employed: (i) at row 3, the CIS cost is recovered by recognizing the tax shield benefit in the first four years, and a deemed equity level of 35% is assumed; (ii) ABSU is not awarded the Customer Care contract, so there are transition costs included at row 9; (iii) at row 10, the new CIS service provider contract cost is $60 million per year; and (iv) the

IR Annual Adjustment is 1%. The illustrative example sets out the steps that are followed, and the amortization model that is used, to derive the 2007 Customer Care Revenue Requirement Variance and the Normalized Customer Care Revenue Requirements for 2007 to 2012.

Customer Care and CIS Settlement Template

#	Category of Cost	A 2007	B 2008	C 2009	D 2010	E 2011	F 2012	G Totals
	CIS Related Categories							
1	*Old CIS Licence Fee*							
2	*Old CIS Hosting and Support*	$14,200,000	$9,800,000	$4,900,000	$0	$0	$0	$28,900,000
2a	*Incumbent (CWLP) CIS Services being provided from January to March 2007*							
3	*New CIS Capital Cost*	$0	$0	$880,000	($5,340,000)	$25,810,000	$24,860,000	$46,210,000
4	*New CIS Hosting and Support*	$0	$0	$4,350,000	$8,700,000	$8,700,000	$8,700,000	$30,450,000
5	*CIS Backoffice (EGD Staffing)*	$1,000,000	$1,030,000	$2,000,000	$2,060,000	$2,121,800	$2,185,454	$10,397,254
6	*SAP Licence Fees*	$0	$0	$1,113,500	$2,227,000	$2,227,000	$2,227,000	$7,794,500
7	*SAP Modifications*	$0	$0	$1,000,000	$1,000,000	$0	$0	$2,000,000
	Customer Care Related Categories							
8	*Incumbent (CWLP) Customer Care Services being provided from - January to March 2007*	$16,900,000	$0	$0	$0	$0	$0	$16,900,000
9	*Customer Care Transition Service Provider Contract Cost - ABSU April, 2007 to Sep 30, 2008*	Up to $52,263,000	Up to $42,623,000	$0	$0	$0	$0	$0
10	*New Service Provider Contract Cost*	TBD	TBD	TBD	TBD	TBD	TBD	$0
11	*Customer Care Licences*	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$8,400,000
12	*Customer Care Backoffice (EGD staffing)*	$3,100,000	$3,193,000	$3,288,790	$3,387,454	$3,489,077	$3,593,750	$20,052,071
13	*Customer Care Procurement Costs*	$0	$980,000	$980,000	$980,000	$980,000	$980,000	$4,900,000
14	*Transition Costs - Consultants and ISP*	$0	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$11,100,000
15	*Transition Costs - EGD Staffing*							
16	**Total CIS & Customer Care**	TBD	TBD	TBD	TBD	TBD	TBD	TBD
17	*Number of Customers*	1,831,283	1,878,004	1,925,563	1,973,575	2,021,588	2,069,600	11,699,613

Customer Care and CIS Settlement Template - Example for purpose of illustrating True-Up

#	Category of Cost	A 2007	B 2008	C 2009	D 2010	E 2011	F 2012	G Totals
	CIS Related Categories							
1	Old CIS Licence Fee							
2	Old CIS Hosting and Support	$14,200,000	$9,800,000	$4,900,000	$0	$0	$0	$28,900,000
2a	Incumbent (CWLP) CIS Services being provided from January to March 2007							
3	New CIS Capital Cost (Intervenor Model @ 35% Equity)	$0	$0	$880,000	($5,340,000)	$25,810,000	$24,860,000	$46,210,000
4	New CIS Hosting and Support	$0	$0	$4,350,000	$8,700,000	$8,700,000	$8,700,000	$30,450,000
5	CIS Backoffice (EGD Staffing)	$1,000,000	$1,030,000	$2,000,000	$2,060,000	$2,121,800	$2,185,454	$10,397,254
6	SAP Licence Fees	$0	$0	$1,113,500	$2,227,000	$2,227,000	$2,227,000	$7,794,500
7	SAP Modifications	$0	$0	$1,000,000	$1,000,000	$0	$0	$2,000,000
	Customer Care Related Categories							
8	Incumbent (CWLP) Customer Care Services being provided from - January to March 2007	$16,900,000	$0	$0	$0	$0	$0	$16,900,000
9	Customer Care Transition Service Provider Contract Cost - ABSU April, 2007 to Sep 30, 2008	$52,263,530	$42,623,220	$0	$0	$0	$0	$94,886,750
10	New Service Provider Contract Cost - (Values placed for illustrative purposes)	$0	$24,000,000	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$264,000,000
11	Customer Care Licences	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$8,400,000
12	Customer Care Backoffice (EGD staffing)	$3,100,000	$3,193,000	$3,288,790	$3,387,454	$3,489,077	$3,593,750	$20,052,071
13	Customer Care Procurement Costs	$0	$980,000	$980,000	$980,000	$980,000	$980,000	$4,900,000
14	Transition Costs - Consultants and ISP	$0	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$11,100,000
15	Transition Costs - EGD Staffing							
16	**Total CIS & Customer Care**	$88,863,530	$85,246,220	$82,132,290	$76,634,454	$106,947,877	$106,166,204	$545,990,575
17	Number of Customers	1,831,283	1,878,004	1,925,563	1,973,575	2,021,588	2,069,600	11,699,613

	True-Up Process Step	A	B	C	D	E	F	G
18	The Normalized 2007 Customer Care Revenue Requirement can be determined. This will be calculated by starting with the Total Customer Care Revenue Requirement for 2007 to 2012, which is the amount in box G16	$545,990,575						
19	That Total Customer Care Revenue Requirement will then be placed into an amortization model that calculates, using the IR annual adjustment that is approved for Enbridge Gas Distribution, the Normalized 2007 Customer Care Revenue Requirement which is the number that, when adjusted for IR annual adjustment for each year from 2008 through 2012, will allow the Company to fully recover the Total Customer Care Revenue Requirement for 2007 to 2012	$88,749,876.15						
20	The Normalized 2007 Customer Care Revenue Requirement will then be compared to the 2007 placeholder of $90.8 million, and the difference will be the 2007 Customer Care Revenue Requirement Variance.	($2,050,124)						
21	The Company will credit or debit the 2007 Customer Care Revenue Requirement Variance, as the case may be, to the 2007 Customer Care Variance Account. The balance in that account will be repaid to the ratepayers, or charged to the ratepayers, with interest, over the course of 2008 to 2012.		($410,025)	($410,025)	($410,025)	($410,025)	($410,025)	
22	The Normalized 2008 Customer Care Revenue Requirement will be the Normalized 2007 Customer Care Revenue Requirement, plus or minus the IR annual adjustment that is approved for Enbridge Gas Distribution.		$89,637,375	$90,533,749	$91,439,086	$92,353,477	$93,277,012	
23	Total Customer Care Revenue By Year (Including repayment of 2007 variance)	$ 90,800,000	$ 89,227,350	$ 90,123,724	$ 91,029,061	$ 91,943,452	$ 92,866,987	$ 545,990,575
24	Normalized Customer Care Revenue Requirement Per Customer without Bad Debt	$ 49.58	$ 47.51	$ 46.80	$ 46.12	$ 45.48	$ 44.87	
25	IR Annual Adjustment	1%						

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Capital Structure
65% Incremental Long Term Debt / 35% Equity

		Col. 1	Col. 2	Col. 3	Col. 4
Line No.		Component	Indicated Cost Rate	Return Component	(4 dec.) Return Component
		%	%	%	%
1.	Long-term debt	65.00	5.35	3.48	3.4775
2.	Short-term debt	0.00	0.00	0.00	0.0000
3.		65.00		3.48	3.4775
4.	Preference shares	0.00	0.00	0.00	0.0000
5.	Common equity	35.00	8.39	2.94	2.9365
6.		100.00		6.42	6.4140

	($Millions)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
7.	Ontario Utility Income ($M)	6.69	9.89	(10.77)	(10.92)	(11.07)	(11.22)	(11.37)	(11.52)	(11.67)	(11.81)
8.	Rate base ($M)	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
9.	Indicated rate of return %	5.921 %	9.783 %	(12.074)%	(14.125)%	(16.921)%	(20.963)%	(27.311)%	(38.734)%	(65.372)%	(198.101)%
10.	(Deficiency) in rate of return %	(0.493)%	3.369 %	(18.488)%	(20.539)%	(23.335)%	(27.377)%	(33.725)%	(45.148)%	(71.786)%	(204.515)%
11.	Net (deficiency) ($M)	(0.56)	3.41	(16.49)	(15.88)	(15.27)	(14.65)	(14.04)	(13.43)	(12.81)	(12.19)
12.	Gross (deficiency) ($M)	(0.88)	5.34	(25.81)	(24.86)	(23.90)	(22.93)	(21.98)	(21.02)	(20.05)	(19.08)

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Rate Base

($Millions)

Line No.		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Property, plant, and equipment										
1.	Cost or redetermined value	118.93	118.93	118.93	118.93	118.93	118.93	118.93	118.93	118.93	118.93
2.	Accumulated depreciation	(5.95)	(17.84)	(29.73)	(41.62)	(53.51)	(65.41)	(77.30)	(89.19)	(101.08)	(112.97)
3.	Net Property, plant, and equipment	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
	Allowance for working capital										
4.	Accounts receivable merchandise finance plan	-	-	-	-	-	-	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-	-	-	-	-	-	-
6.	Materials and supplies	-	-	-	-	-	-	-	-	-	-
7.	Mortgages receivable	-	-	-	-	-	-	-	-	-	-
8.	Customer security deposits	-	-	-	-	-	-	-	-	-	-
9.	Prepaid expenses	-	-	-	-	-	-	-	-	-	-
10.	Gas in storage	-	-	-	-	-	-	-	-	-	-
11.	Working cash allowance	-	-	-	-	-	-	-	-	-	-
12.		-	-	-	-	-	-	-	-	-	-
13.	Ontario utility rate base	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Income

($Millions)

Line No.		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Revenue										
1.	Gas sales	-	-	-	-	-	-	-	-	-	-
2.	Transportation of gas	-	-	-	-	-	-	-	-	-	-
3.	Transmission and compression	-	-	-	-	-	-	-	-	-	-
4.	Storage service	-	-	-	-	-	-	-	-	-	-
5.	Other operating revenue	-	-	-	-	-	-	-	-	-	-
6.	Interest and property rental	-	-	-	-	-	-	-	-	-	-
7.	Other income	-	-	-	-	-	-	-	-	-	-
8.	Total revenue	-	-	-	-	-	-	-	-	-	-
	Costs and expenses										
9.	CIS -selection procurement cost	5.10	-	-	-	-	-	-	-	-	-
10.	Operation and maintenance	-	-	-	-	-	-	-	-	-	-
11.	Depreciation and amortization	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
12.	Provincial capital taxes	0.16	-	-	-	-	-	-	-	-	-
13.	Total costs and expenses	17.15	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
14.	**Utility income before inc. taxes**	(17.15)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)
	Income taxes										
15.	Excluding interest shield	(22.42)	(20.51)	-	-	-	-	-	-	-	-
16.	Tax shield on interest expense	(1.42)	(1.27)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
17.	Total income taxes	(23.84)	(21.78)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
18.	**Ontario utility net income**	6.69	9.89	(10.77)	(10.92)	(11.07)	(11.22)	(11.37)	(11.52)	(11.67)	(11.81)

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Taxable Income and Income Tax Expense

($Millions)

Line No.		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1.	Utility income before income taxes	(17.15)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)
	Add Backs										
2.	Depreciation and amortization	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
3.	Large corporation tax	-	-	-	-	-	-	-	-	-	-
4.	Other non-deductible items	-	-	-	-	-	-	-	-	-	-
5.	Any other add back(s)	-	-	-	-	-	-	-	-	-	-
6.	Total added back	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
7.	Sub total - pre-tax income plus add backs	(5.26)	-	-	-	-	-	-	-	-	-
	Deductions										
8.	Capital cost allowance - Federal	56.80	56.80	-	-	-	-	-	-	-	-
9.	Capital cost allowance - Provincial	56.80	56.80	-	-	-	-	-	-	-	-
10.	Items capitalized for regulatory purposes	-	-	-	-	-	-	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-	-	-	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-	-	-	-	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-	-	-	-	-	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-	-	-	-	-	-	-
15.	Any other deduction(s)	-	-	-	-	-	-	-	-	-	-
16.	Total Deductions - Federal	56.80	56.80	-	-	-	-	-	-	-	-
17.	Total Deductions - Provincial	56.80	56.80	-	-	-	-	-	-	-	-
18.	Taxable income - Federal	(62.06)	(56.80)	-	-	-	-	-	-	-	-
19.	Taxable income - Provincial	(62.06)	(56.80)	-	-	-	-	-	-	-	-
20.	Income tax provision - Federal @ 22.12 %	(13.73)	(12.56)	-	-	-	-	-	-	-	-
21.	Income tax provision - Provincial @ 14.00 %	(8.69)	(7.95)	-	-	-	-	-	-	-	-
22.	Income tax provision - combined	(22.42)	(20.51)	-	-	-	-	-	-	-	-
23.	Part V1.1 tax	-	-	-	-	-	-	-	-	-	-
24.	Investment tax credit	-	-	-	-	-	-	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(22.42)	(20.51)	-	-	-	-	-	-	-	-
	Tax shield on interest expense										
26.	Rate base as adjusted	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
27.	Return component of debt	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%
28.	Interest expense	3.93	3.52	3.10	2.69	2.28	1.86	1.45	1.03	0.62	0.21
29.	Combined tax rate	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612
30.	Income tax credit	(1.42)	(1.27)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
31.	**Total income taxes**	(23.84)	(21.78)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Revenue Requirement

Line No.	($Millions)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Cost of capital										
1.	Rate base	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
2.	Required rate of return	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%
3.	Cost of capital	7.25	6.48	5.72	4.96	4.20	3.43	2.67	1.91	1.15	0.38
	Cost of service										
4.	CIS -selection procurement cost	5.10	-	-	-	-	-	-	-	-	-
5.	Operation and maintenance	-	-	-	-	-	-	-	-	-	-
6.	Depreciation and amortization	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
7.	Municipal and other taxes	0.16	-	-	-	-	-	-	-	-	-
8.	Cost of service	17.15	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
	Misc. & Non-Op. Rev										
9.	Other operating revenue	-	-	-	-	-	-	-	-	-	-
10.	Other income	-	-	-	-	-	-	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-	-	-	-	-	-	-
	Income taxes on earnings										
12.	Excluding tax shield	(22.42)	(20.51)	-	-	-	-	-	-	-	-
13.	Tax shield provided by interest expens	(1.42)	(1.27)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
14.	Income taxes on earnings	(23.84)	(21.78)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
	Taxes on deficiency										
15.	Gross deficiency	(0.88)	5.34	(25.81)	(24.86)	(23.90)	(22.93)	(21.98)	(21.02)	(20.05)	(19.08)
16.	Net deficiency	(0.56)	3.41	(16.49)	(15.88)	(15.27)	(14.65)	(14.04)	(13.43)	(12.81)	(12.19)
17.	Taxes on deficiency	0.32	(1.93)	9.32	8.98	8.63	8.28	7.94	7.59	7.24	6.89
18.	**Revenue requirement**	0.88	(5.34)	25.81	24.86	23.90	22.93	21.98	21.02	20.06	19.08
	Revenue at existing Rates										
19.	Gas sales	-	-	-	-	-	-	-	-	-	-
20.	Transportation service	-	-	-	-	-	-	-	-	-	-
21.	Transmission, compression and storag	-	-	-	-	-	-	-	-	-	-
22.	Rounding adjustment	-	-	-	-	-	-	-	-	-	-
23.	Revenue at existing rates	-	-	-	-	-	-	-	-	-	-
24.	**Gross revenue deficiency**	(0.88)	5.34	(25.81)	(24.86)	(23.90)	(22.93)	(21.98)	(21.02)	(20.06)	(19.08)

2007 TEST YEAR
FINANCIAL IMPACT OF THE SETTLEMENT PROPOSAL

1. This exhibit is being filed in order to provide the Board with the financial impact of the Settlement Proposal filed at Exhibit N1.T1.S1 against the Company's updated deficiency request filed at Exhibit M1, Tab 2, Schedule 1. Acceptance of the Settlement Proposal will decrease the Company's gross revenue deficiency in the 2007 Test Year by $76.7 million, from $158.7 million as shown at Exhibit M1.T2.S1, to $82.0 million as shown at Exhibit N1, Tab 2, Schedule 2. The $82.0 million gross deficiency amount includes within it, a gross deficiency amount of $29.9 million related to issues which have been agreed to in the Settlement Proposal, and a gross deficiency amount of $52.1 million relating to issues which remain unresolved. The financial adjustments which achieve the $82.0 million deficiency amount are shown within Schedules 2 through 6 of this exhibit while the adjustments which result in the $29.9 million deficiency are shown within Schedule 2, pages 1 and 2.

Rate Base (Exhibit N1.T2.S3)

2. The Company's rate base forecast will decrease by $54.6 million, from $3,798.3 million at Exhibit M1.T2.S2 to $3,743.7 million at Exhibit N1.T2.S3, p.1, Line 13, as a result of the Settlement Proposal.

3. The $56.4 million reduction to the property, plant and equipment portion of rate base is the summary impact of reductions to the capital expenditure budget (Exhibit N1.T1.S1 – Issues 1.1 through 1.8) and the removal of the proposed changes to depreciation rates within the depreciation study (Exhibit N1.T1.S1 – Issue 3.11).

Witness: K. Culbert

4. The working cash allowance component of rate base has been recalculated to reflect the impact of the Settlement Proposal with respect to the decrease in operation and maintenance costs included in the calculation (Exhibit N1.T1.S1. – Issues 1.6 and 3.2), resulting in a $1.8 million increase. A decrease in O&M results in an increase in working cash allowance because of the negative O&M lag day factor embedded in the calculation. A negative O&M lag day factor multiplied by a reduced O&M value, results in a lower credit within the working cash allowance calculation and thus a higher total working cash allowance. The working cash allowance calculation of $2.5 million is filed at Exhibit N1.T2.S3, on page 3, and compares to the level of $0.7 million filed at Exhibit M1.T2.S2, page 3.

<u>Utility Income (Exhibit N1.T2.S4)</u>

5. Acceptance of the Settlement Proposal will result in an increase to the Company's forecast of net income in the amount of $46.2 million, from $188.4 million at Exhibit M1.T2.S3 to $234.6 million at Exhibit N1.T2.S4, pg.1, line 22. The individual revenue and expense items which have been adjusted as a result of the Settlement Proposal can be examined at Exhibit N1.T.2.S4, on pages 1 through 3, and are discussed in the following paragraphs.

6. Other operating revenue will increase by $5.2 million, from $23.7 million at Exhibit M1.T2.S3, line 4 to $28.9 million at Exhibit N1.T2.S4, pg.1, line 4, as a result of the Settlement Proposal for the following:
   - Transactional Services revenue increase of $3.5 million (Exhibit N1.T1.S1 – Issue 2.1),
   - Service charges & DPAC revenue increase of $1.0 million (Exhibit N1.T1.S1 – Issue 2.2); and
   - imputed NGV program revenue of $0.7 million (Exhibit N1.T1.S1 - Issue 2.2).

7. As a result of the Settlement Proposal relating to DSM, Corporate Cost Allocation and Other O&M, operation and maintenance costs will decrease by $24.1 million, from $365.8 million at Exhibit M1.T2.S3, pg.1, line 9 to $341.7 million at Exhibit N1.T2.S4, pg.1, line 9. This is the result of a $0.5 million EnVision related other O&M reduction, a further $18.8 million general reduction to other O&M and a $4.8 million reduction to the corporate cost allocation amount as agreed to in the Settlement Proposal (Exhibit N1.T1.S1 – Issues 1.6 & 3.2).

8. Depreciation and amortization expense decreases by $27.5 million as a result of the Settlement Proposal. Of this decrease, $24.8 million is due to the agreed upon withdrawal of the depreciation rate changes within the proposed depreciation study (Exhibit N1.T1.S1 – Issue 3.11) while $2.7 million is due to the agreed upon reductions to capital expenditures (Exhibit N1.T1.S1 – Issues 1.1 through 1.8).

9. Municipal and other taxes will decrease by $1.7 million, from $47.6 million at Exhibit M1.T2.S3, pg.1, line 14 to $45.9 million (Exhibit N1.T2.S4, pg.1, line 14) as a result of a general reduction to municipal and other taxes of $1.3 million within the Settlement Proposal (Exhibit N1.T1.S1 – Issue 3.14) and a reduction in capital taxes due to capital expenditure reductions within the Settlement Proposal at (Exhibit N1.T1.S1 – Issues 1.1 through 1.8).

10. As a result of the Settlement Proposal, Utility income before income taxes will increase by $58.5 million, which will result in an increase in income taxes excluding the tax shield provided by interest expense in the amount of $12.0 million. The tax shield provided by interest expense will decrease by $0.3 million as a result of the decline in rate base of $54.6 million (Exhibit N1.T2.S3, pg.1, line 13). The decrease

in the tax shield provided by interest expense associated with the decline in rate base is partially offset by a 0.04% increase in the capital structure return component of long and short-term debt which has increased from 4.31% as filed at Exhibit M1.T2.S4, pg.1, Line 3, Col. 4 to 4.35% found at Exhibit N1.T2.S5, pg.1, line 3, Col. 4. Total income taxes will increase by $12.3 million, from $48.1 million filed at Exhibit M1.T2.S3, pg.1, line 21 to $60.4 million at Exhibit N1.T2.S4, pg.1, line 21.

Capital Structure (Exhibit N1.T2.S5)

11. The proposed method and costs of financing capital requirements have been incorporated into the capital structure found (Exhibit N1.T2.S5, pg.1). The overall rate of return on rate base of 7.67% includes an 8.39% rate of return on common equity as determined by the current Board approved formula as agreed to in the Settlement Proposal. (Exhibit N1.T1.S1 - Issue 4.1)

12. Utility income in the amount of $234.6 million represents an indicated return of 6.27% on a rate base of $3,743.7 million, indicating a deficiency in return in the amount of 1.40% in comparison to the requested overall rate of return of 7.67%. This results in a net deficiency of $52.4 million and a gross revenue deficiency of $82.0 million, as shown at Exhibit N1, Tab 2, Schedule 5.

13. Acceptance of the Settlement Proposal will result in a gross revenue deficiency of $82.0 million, which is a decrease of $76.7 million, as shown at Exhibit N1, Tab 2, Schedule 6, in comparison to the Company's deficiency request filed at Exhibit M1, Tab 2, Schedules 4 & 5 in the amount of $158.7 million.

Utility ADR Impact Summary
2007 Test Year

Line No.		Col. 1 Reference	Col. 2 ($Millions)
1.	Utility rate base	N1.T2.S3.P1*	3,743.7
2.	Utility income	N1.T2.S4.P1	234.6
3.	Indicated rate of return	N1.T2.S5.P1	6.27%
4.	Requested rate of return	N1.T2.S5.P1	7.67%
5.	(Deficiency) in rate of return	N1.T2.S5.P1	(1.40)%
6.	Net (deficiency)	N1.T2.S5.P1	(52.4)
7.	Gross (deficiency)	N1.T2.S5.P1	(82.0)
8.	Revenue at existing rates	N1.T2.S6.P1	3,071.8
9.	Revenue requirement	N1.T2.S6.P1	3,153.8
10.	Gross revenue (deficiency)	N1.T2.S6.P1	(82.0)
11.	Unsettled Issues and Gross deficiency amounts to be resolved (N1.T2.S2.page 2)		52.1
12.	ADR Resolved Issues and embedded Gross Deficiency		(29.9)

*N1.T2.S2.P1 refers to Exhibit N1, Tab 2, Schedule 2, page 1.

2007 Test Year
Deficiency for Implementation April 1, 2007

Line No.		Col. 1 Gross Deficiency Amount ($millions)
1.	Post ADR Settlement Proposal Gross Deficiency (includes deficiency amounts for settled and unsettled / unresolved issues)	(82.0)
	Unsettled / Unresolved Issues and embedded Deficiency amounts	
2.	Customer support costs in filing vs. in existing rates ($120.1 vs. 104.1)	16.0
3.	Transition costs in filing versus in existing rates	10.0
4.	Equity at 38% versus 35% in existing rates (Updated 2007-01-18, A2.T5.S1, col.4)	10.0
5.	Change in volumes deficiency impact (Updated 2007-01-18, A2.T5.S1, col.2)	16.1
6.	Sub-total Unsettled / Unresolved Issues and Gross Deficiency	52.1
7.	ADR Resolved Issues and embedded Gross Deficiency	(29.9)

Utility Rate Base
2007 Test Year

Line No.		Col. 1 Impact No.1 Filed: 2006-12-06 M1.T2.S2	Col. 2 Adjustments	Col. 3 ADR Utility Rate Base
		($Millions)	($Millions)	($Millions)
	Property, plant, and equipment			
1.	Cost or redetermined value	5,048.3	(69.6)	4,978.7
2.	Accumulated depreciation	(1,852.6)	13.2	(1,839.4)
3.		3,195.7	(56.4)	3,139.3
	Allowance for working capital			
4.	Accounts receivable merchandise finance plan	0.1		0.1
5.	Accounts receivable rebillable projects	6.9		6.9
6.	Materials and supplies	21.0		21.0
7.	Mortgages receivable	0.9		0.9
8.	Customer security deposits	(42.8)		(42.8)
9.	Prepaid expenses	2.7		2.7
10.	Gas in storage	613.1		613.1
11.	Working cash allowance	0.7	1.8	2.5
12.	Total Working Capital	602.6	1.8	604.4
13.	**Utility rate base**	3,798.3	(54.6)	3,743.7

Explanation of Adjustments to Utility Rate Base
2007 Test Year

Line No. Adj'd	Adjustments ($Millions)	Explanation
1.	(69.6)	**Cost or redetermined value** To reflect the impact of capital expenditure reductions, due to the settlement of Issues 1.1 through 1.8, on the value of gross plant within rate base.
2.	13.2	**Accumulated depreciation** To reflect the impact on accumulated depreciation arising from capital expenditure reductions due to the settlement of Issues 1.1 through 1.8, and from a return to the use of existing Board Approved depreciation rates as a result of the settlement of Issue 3.11.
11.	1.8	**Working cash allowance** To reflect the impact on the Company's working cash allowance as a result of changes to operation and maintenance expenses as per the Settlement Proposal. An explanation of changes to operation and maintenance expenses can be found in Exhibit N1, Tab 2, Schedule 4. The working cash allowance calculation can be found on Exhibit N1, Tab 2, Schedule 3, page 3.

Working Capital Components - Working Cash Allowance
2007 Test Year

		Col. 1	Col. 2	Col. 3	Col. 4
Line No.		Reference	Disburs-ements	Net Lag-Days	Allowance
			($Millions)	(Days)	($Millions)
1.	Gas purchase and storage and transportation charges		2,265.7	3.7	23.0
2.	Items not subject to working cash allowance	(Note 1)	(95.1)		
3.	Gas costs charged to operations		2,170.6		
4.	Operation and Maintenance		341.7		
5.	Less: Storage costs		(6.9)		
6.	Operation and maintenance costs subject to working cash		334.8	(27.4)	(25.1)
7.	Sub-total				(2.1)
8.	Storage costs		6.9	52.9	1.0
9.	Storage municipal and capital taxes		1.5	35.5	0.1
10.	Sub-total				1.1
11.	Goods and services tax				3.5
12.	Total working cash allowance				2.5

Note 1: Represents non-cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

Gas in Storage
Month End Balances and Average of Monthly Averages
2007 Test Year

Line No.		Volume	Col. 1 Impact No.1 Filed: 2006-12-06 M1.T2.S2	Col. 2 Adjustments	Col. 3 ADR Value
		10*6 M*3	($Millions)	($Millions)	($Millions)
1.	January 1	1,848.2	785.3		785.3
2.	January 31	1,397.6	589.6		589.6
3.	February	1,048.0	437.2		437.2
4.	March	809.0	333.7		333.7
5.	April	768.7	317.1		317.1
6.	May	927.1	383.7		383.7
7.	June	1,151.6	478.8		478.8
8.	July	1,411.3	588.9		588.9
9.	August	1,731.4	721.8		721.8
10.	September	2,078.1	863.1		863.1
11.	October	2,276.0	941.2		941.2
12.	November	2,220.2	912.2		912.2
13.	December	1,958.3	794.4		794.4
14.	**Avg. of monthly avgs.**	1,476.9	613.1	-	613.1

Utility Income
2007 Test Year

Line No.		Col. 1 Impact No.1 Filed: 2006-12-06 M1.T2.S3 ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 ADR Utility Income ($Millions)
	Revenue			
1.	Gas sales	2,348.9		2,348.9
2.	Transportation of gas	720.9		720.9
3.	Transmission and compression & storage	1.9		1.9
4.	Other operating revenue	23.7	5.2	28.9
5.	Interest and property rental	-		-
6.	Other income	0.2		0.2
7.	**Total revenue**	3,095.6	5.2	3,100.8
	Costs and expenses			
8.	Gas costs	2,170.6		2,170.6
9.	Operation and maintenance	365.8	(24.1)	341.7
10.	Transition costs customer care	10.0		10.0
11.	Depreciation and amortization	254.6	(27.5)	227.1
12.	Fixed financing costs	1.3		1.3
13.	Notional utility account recovery	9.2		9.2
14.	Municipal and other taxes	47.6	(1.7)	45.9
15.	Interest and financing amortization expense	-		-
16.	Other interest expense	-		-
17.	**Total costs and expenses**	2,859.1	(53.3)	2,805.8
18.	Utility income before income taxes	236.5	58.5	295.0
	Income taxes			
19.	Excluding interest shield	107.2	12.0	119.2
20.	Tax shield on interest expense	(59.1)	0.3	(58.8)
21.	Total income taxes	48.1	12.3	60.4
22.	**Utility net income**	188.4	46.2	234.6

Explanation of Adjustments to Utility Income
2007 Test Year

Line No. Adj'd	Adjustments ($Millions)	Explanation
4.	5.2	**Other operating revenue** To reflect the impact of a $3.5 million increase in the ratepayer guaranteed amount of Transactional Services revenue, an increase in Other Revenue of $1.0 million, and imputing revenue of $0.7 million to the NGV program as a result of the settlement of Issues 2.1 and 2.2.
9.	(24.1)	**Operation and maintenance** To reflect the impact of a $0.5 million Envision related O&M reduction, a $4.8 million reduction to achieve the agreed upon corporate cost allocation amount of $18.1 million, and a further $18.8 million reduction to achieve the agreed upon other O&M amount of $181.5 million per the settlement of Issues 1.6 and 3.2.
11.	(27.5)	**Depreciation and amortization** To reflect the impact on depreciation and amortization arising from capital expenditure reductions due to the settlement of Issues 1.1 through 1.8, and from a return to the use of existing Board Approved depreciation rates as a result of the settlement of Issue 3.11.
14.	(1.7)	**Municipal and other taxes** To reflect the impact of a $1.3 million reduction to municipal taxes, per the settlement of Issue 3.14, and a $0.4 million reduction to capital taxes that results from the reduction of capital expenditures agreed to in Issues 1.1 through 1.8 of the Settlement Proposal.
19.	12.0	**Income taxes - excluding interest shield** To reflect adjustments to utility income taxes as a result of the above noted changes contributing to higher taxable income and income tax excluding the interest tax shield. The Utility's income tax calculations are found in Exhibit N1, Tab 2, Schedule 4, page 3.

Utility Taxable Income and Income Tax Expense
2007 Test Year

Line No.		Col. 1 Impact No.1 Filed: 2006-12-06 M1.T2.S3.p3	Col. 2 Adjustments	Col. 3 ADR Utility Tax
		($Millions)	($Millions)	($Millions)
1.	Utility income before income taxes	236.5	58.5	295.0
	Add Backs			
2.	Depreciation and amortization	254.6	(27.5)	227.1
3.	Other non-deductible items	1.2		1.2
4.	Total Add Back	255.8	(27.5)	228.3
5.	Sub total	492.3	31.0	523.3
	Deductions			
6.	Capital cost allowance - Federal	163.3	(2.4)	160.9
7.	Capital cost allowance - Provincial	163.2	(2.4)	160.8
8.	Items capitalized for regulatory purposes	28.7		28.7
9.	Deduction for "grossed up" Part VI.1 tax	5.9		5.9
10.	Amortization of share/debenture issue expense	2.6		2.6
11.	Amortization of cumulative eligible capital	0.1		0.1
12.	Amortization of C.D.E. and C.O.G.P.E	0.3		0.3
13.	Total Deduction - Federal	200.9	(2.4)	198.5
14.	Total Deduction - Provincial	200.8	(2.4)	198.4
15.	Taxable income - Federal	291.4	33.4	324.8
16.	Taxable income - Provincial	291.5	33.4	324.9
17.	Income tax provision - Federal	64.5	7.3	71.8
18.	Income tax provision - Provincial	40.8	4.7	45.5
19.	Income tax provision - combined	105.3	12.0	117.3
20.	Part V1.1 tax			2.0
21.	Investment tax credit			(0.1)
22.	Total taxes excluding tax shield on interest expense			119.2
	Tax shield on interest expense			
23.	Rate base			3,743.7
24.	Return component of debt			4.35%
25.	Interest expense			162.9
26.	Combined tax rate			36.12%
27.	Income tax credit			(58.8)
28.	Total income taxes			60.4

Utility Capital Structure
2007 Test Year

Line No.		Col. 1 Principal	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	2,234.4	59.68	7.31	4.36
2.	Short term debt	(13.2)	(0.35)	4.12	(0.01)
3.		2,221.2	59.33		4.35
4.	Preference shares	99.9	2.67	5.00	0.13
5.	Common equity	1,422.6	38.00	8.39	3.19
6.		3,743.7	100.00		7.67
7.	Utility income	($Millions)			234.6
8.	Utility Rate base	($Millions)			3,743.7
9.	Indicated rate of return				6.27%
10.	(Deficiency) in rate of return				(1.40)%
11.	Net (deficiency)	($Millions)			(52.4)
12.	Gross (deficiency)	($Millions)			(82.0)
13.	Revenue at existing rates	($Millions)			3,071.8
14.	Revenue requirement	($Millions)			3,153.8
15.	Gross revenue (deficiency)	($Millions)			(82.0)

Change in Revenue Requirement
2007 Test Year

Line No.		Col. 1 ADR Settlement Proposal	Col.2 Impact No.1 Filed: 2006-12-06 M1.T2.S5	Col.3 Change (Col.1-Col.2)
		($Millions)	($Millions)	($Millions)
	Cost of capital			
1.	Rate base	3,743.7	3,798.3	(54.6)
2.	Required rate of return	7.67%	7.63%	
3.	Cost of capital	287.1	289.8	(2.7)
	Cost of service			
4.	Gas costs	2,170.6	2,170.6	-
5.	Operation and maintenance	341.7	365.8	(24.1)
6.	Transition costs customer care	10.0	10.0	-
7.	Depreciation and amortization	227.1	254.6	(27.5)
8.	Fixed financing expense	1.3	1.3	-
9.	Notional utility account recovery	9.2	9.2	-
10.	Municipal and other taxes	45.9	47.6	(1.7)
11.	Cost of service	2,805.8	2,859.1	(53.3)
	Miscellaneous operating and non-operating income			
12.	Other operating revenue	(28.9)	(23.7)	(5.2)
13.	Interest and property rental	-	-	-
14.	Other income	(0.2)	(0.2)	-
15.	Misc. operating and non-operating income	(29.1)	(23.9)	(5.2)
	Income taxes on earnings			
16.	Excluding tax shield	119.2	107.2	12.0
17.	Tax shield provided by interest expense	(58.8)	(59.1)	0.3
18.	Income taxes on earnings	60.4	48.1	12.3
	Taxes on sufficiency / (deficiency)			
19.	Gross sufficiency / (deficiency)	(82.0)	(158.7)	76.7
20.	Net sufficiency / (deficiency)	(52.4)	(101.4)	49.0
21.	Income taxes on sufficiency / (deficiency)	29.6	57.3	(27.7)
22.	**Revenue requirement**	3,153.8	3,230.4	(76.6)
	Revenue at existing Rates			
23.	Gas sales	2,348.9	2,348.9	-
24.	Transportation service	720.9	720.9	-
25.	Transmission, compression and storage	1.9	1.9	-
26.	Sub-total	3,071.7	3,071.7	-
27.	Rounding adjustment	0.1	-	0.1
28.	Revenue at existing rates	3,071.8	3,071.7	0.1
29.	**Gross revenue sufficiency / (deficiency)**	(82.0)	(158.7)	76.7

APPENDIX "B"

TO INTERIM RATE ORDER

BOARD FILE NO. EB-2006-0034

DATED MARCH 26, 2007

Supporting Documentation

Documentation for Working Papers Supporting the EB-2006-0034 Interim Rate Order

The attached working papers provide support for the Rate Handbook filed as Appendix A to the Draft Interim Rate Order for January 1, 2007 interim rates. The Rate Handbook reflects the OEB approved EB-2006-0034 Settlement Agreement as filed at Exhibit N1, Tab 1, Schedule 1.

The rates shown in the Rate Handbook are designed to recover the revenue requirement stemming from the EB-2006-0034 Settlement Agreement and incorporate the July 1, 2006 (EB-2006-0099) rates as the base rates. The revenue deficiency as outlined in the Settlement Agreement is derived based on the following:

	($'000)	Reference
Revenue at Existing Rates	3,072.6	H2, Tab 2, Schedule 1 Including DPAC
Revenue Requirement	3,098.6	H2, Tab 2, Schedule 1 Including DPAC
Gross Revenue Deficiency	26.0	

The following sections have been changed or removed in the Rate Handbook and result from the EB-2006-0034 Settlement Agreement:

Issue	Location in Handbook
6.3 - Glossary of Terms	
Affiliated Gas Users	Page 1
Annual Contract Demand ("ACD")	Page 1
Authorized Volume	Page 1
Banked Gas Account	Page 1
Billing Contract Demand	Page 1
Billing Month	Page 1
Bundled Service	Page 1
Buy/Sell Price	Page 1
Contract Demand	Page 1
Curtailment Credit	Page 1
Daily Capacity Repurchase Quantity	Page 1
Customer Charge	Page 1
Daily Gas Quantity	Page 1
Demand Charge	Page 2
Direct Purchase	Page 2
Firm Service	Page 2
Firm Service Tendered ("FST")	Page 2
Firm Transportation ("FT")	Page 2
Gas Purchase Agreement	Page 2
Gas Sale Contract	Page 2
Gas Supply Load Balancing Charge	Page 2

The working papers are laid out as follows:

H2: Design of Rates using FACS shown at G2
G2: Fully Allocated Cost Study (FACS) using 2007 Board Approved methodology

Description of H2 Exhibits

The rates shown in the H2 exhibits are designed to recover the allocation of the revenue requirement based on the cost allocation methodology as approved in the EB-2006-0034 Settlement Agreement.

All exhibits in the H2 series follow the same format as in previous rate filings and rate orders and are listed below:

a) Tab 1, Schedule 1 of this exhibit summarizes, by rate class, and rate component, the revenues at existing and 2007 Interim rates found in EB-2006-0034. The forecast of billed revenues at 2006 July QRAM rates (Interim EB-2006-0099) is shown in columns 1 through 5. The revenues at the 2007 Interim rates are shown in columns 11 through 15. The net change in revenue, or the revenue deficiency/sufficiency, by component, is shown in columns 6 to 10. The total in column 10 indicates the forecast revenue deficiency that will be recovered from billed revenues. Schedule 2 displays the revenue requirement, unit rates and associated volumes by rate class and component.

b) The Tab 2 schedule summarizes the revenues shown in Schedule 1 and presents the unbilled revenues at current and 2007 Interim rates to yield calendar year revenues.

c) The schedule at Tab 3 compares the unit rates from EB-2006-0099 to the 2007 Interim unit rates.

d) Exhibits under Tab 4 show the derivation of gas supply commodity, gas supply load balancing rates and transportation rates from the cost allocated to the rate classes in the FACS which is found at Exhibit G2. The derivation of the Seasonal credits is found at page 3.

e) The schedules under Tab 5 show the detailed revenue calculations by rate class.

f) Annual bill comparisons indicating the impact of the 2007 Interim rates on typical customers relative to the July 1, 2006 rates are shown at Tab 7.

g) Tab 8 shows the derivation of the Rider E unit rates. The unit rates are derived by comparing the revenue at existing rates (EB-2006-0099) to the revenue at 2007 Interim rates. The revenues are based on the rates applied to the 2007 forecast volumes for the months of April to December 2007. This analysis can be found in pages 3 to 7 of Tab 8. Page 2 of Tab 8 derives the unit rates by component based on the change in revenue divided by the forecast volume. Page 1 is the determination of the unit rates based on the type of service.

DOCUMENTATION FOR WORKING PAPERS SUPPORTING THE SETTLEMENT PROPOSAL: EB-2006-0034

Description of Cost Allocation (G2) Exhibits

The G2 exhibits, also referred to as the Fully Allocated Cost Study (FACS), allocate the test year revenue requirement to the customer rate classes.

All G2 series exhibits have been updated for the Impact Statement No.1 (EB-2006-0034, Exhibit M1), which the Company filed with the Board on December 06, 2006, and the Settlement Proposal (EB-2006-0034, Exhibit N1), which the Board approved on January 29, 2007.

The cost of service total of $3,098.6 million shown at G2/T2/S1/P1/L4/C1 equals revenues at existing rates of $3,071.8 million (N1/T2/S2/P1/L8/C2), plus direct purchase revenues at existing rates of $0.9 million (H2/T2/S1/P1/L15/C4), plus a settled deficiency in the amount of $26.0 million (N1/T1/S1/P46/Item 9.1).

As outlined in the Settlement Proposal at Issue 9.1, the parties agree that the Company can adjust rates to recover a $26.0 million deficiency effective as of January 1, 2007.

In its original filing the Company requested a $167.8 million deficiency. The Impact Statement No. 1 and Settlement Proposal adjustments reduce the deficiency to $26.0 million as follows:

Original Deficiency	167.8
Adjustments to Net Investments	(30.4)
Adjustments to O&M and Storage Costs	(28.5)
Adjustments to Return and Taxes	(82.9)
Deficiency from the Settlement Proposal to be Recovered in Rates Effective Jan. 01, 2007	26.0

Notes:

1) Adjustments reflect total net adjustments in Tables 2, 3 and 4 below.

The adjustments to rate base, net investments and operating and maintenance (O&M) expenses reflect the specific impacts of settled issues. The adjustments to return and taxes reflect the impact on return and taxes from settled issues and also capture deficiency consequences from unsettled issues.

The following four tables illustrate how the adjustments were made in the FACS for both the Impact Statement No. 1 and the Settlement Proposal.

The adjustments are compared to the Company's original filing with respect to:

- rate base for plant, equipment and working capital allowance;
- net investments;
- O&M and storage costs; and
- return and taxes.

Table 1: Rate Base Adjustments to Plant, Equipment and Working Capital Allowance

#	Item	Impact Statement Adjustment	Settlement Proposal Adjustment	Net Adjustment	Reference
1.0	Distribution Plant(1)	0	(56.4)	(56.4)	G2/T3/S1/P1/L2/C1
2.0	General Plant	0	0	0	G2/T3/S1/P1/L3/C1
3.0	Working Capital Allow.(2)	(3.0)	1.8	(1.2)	G2/T3/S1/P1/L6/C1
4.0	Total	(3.0)	(54.6)	(57.6)	

Notes:

1) The impact on rate base and accumulated depreciation from the settlement of Issues 1.1 through 1.8 and Issue 3.11.

2) The impact on working capital allowance from the EB-2005-0551 NGEIR Decision to reflect cost-based storage rates for services acquired from Union Gas and from reduction to O&M expenses as per the Settlement Proposal.

Table 2: Adjustments to Net Investments

#	Item	Impact Statement Adjustment	Settlement Proposal Adjustment	Net Adjustment	Reference
1.1	Depreciation(1)	0	(27.5)	(27.5)	G2/T3/S3/P1/L1.1/C1
1.2	Other Taxes(2)	0	(1.7)	(1.7)	G2/T3/S3/P1/L1.2+1.3/C1
1.0	Total Investments	0	(29.2)	(29.2)	G2/T3/S3/P1/L1/C1
2.0	Misc. Revenues(3)	3.5	(4.7)	(1.2)	G2/T3/S3/P1/L2/C1
3.0	Total	3.5	(33.9)	(30.4)	

Notes:

1) The impact on depreciation and amortization from reduction in capital expenditures and from existing Board-approved depreciation rates as per the settlement of Issues 1.1 through 1.8 and Issue 3.11 respectively.

2) The impact on other taxes from $1.3 M reduction in municipal taxes and $0.4 M reduction in capital taxes as per the settlement of Issue 3.14 and Issues 1.1 through 1.8 respectively.

3) The impact on misc. revenues from transactional services' revenues and increases in other and NGV program revenues. Note that misc. revenues are shown as credits in G2 exhibits.

Table 3: Adjustments to Operating and Maintenance (O&M) and Storage Costs

#	Item	Impact Statement Adjustment	Settlement Proposal Adjustment	Net Adjustment	Reference
1.0	Storage with Union Gas(1)	(6.0)	0	(6.0)	G2/T6/S2/P2/L4.1+4.2/C3
2.0	DSM and other(2)	1.6	0	1.6	G2/T3/S4/P2/L4.10+4.11/C1
3.0	Utility O&M and Storage(3)	0	(24.1)	(24.1)	G2/T3/S4 & G2/T6+7/S2+3
4.0	Total	(4.4)	(24.1)	(28.5)	

Notes:

1) The impact on storage service with Union Gas from the EB-2005-0551 NGEIR Decision to reflect cost-based storage rates.

2) The impact on DSM from the EB-2006-0021 Decision to set DSM budget at $22.0 M, which required an increase of $1.7 M to the $20.3 M DSM budget embedded in the original filing. Includes a $0.1 M reduction in other O&M for which reference is not provided.

3) The impact on utility O&M and storage costs from the Settlement Proposal. These adjustments are reflected in exhibits G2/T3/S4/Items 2 through 8/C1 and G2/T6/S2/P2/L1.5+2.4 and G2/T7/S3/P1/L2.1+2.2+2.3.

Table 4: Adjustments to Return & Taxes

#	Item	Impact Statement Adjustment	Settlement Proposal Adjustment	Net Adjustment	Reference
1.0	Return & Taxes	(7.8)	(71.3)	(79.1)	G2/T5/S3/P1/L6/C3
2.0	Tecumseh Return & Taxes	(0.4)	(3.4)	(3.8)	G2/T7/S3/P1/L1
3.0	Total(1)	(8.2)	(74.7)	(82.9)	

Notes:

1) The impact on return and taxes from settled issues and deficiency consequences from unsettled issues.

The G2 exhibits provided in this filing follow the same format as in previous rate filings or rate orders:

a) Tab 2 exhibits provide a summary of the FACS' results. They outline the allocation of the proposed revenue requirement, return on the allocated rate base and the revenue to cost ratio by rate class.

b) Tab 3 exhibits functionalize rate base, working capital, net investment, and O&M costs into similar operating functions to facilitate identification of costs that are associated with a distinct aspect of the Company. The functionalization of costs allows for consistent treatment of similar costs.

c) Tab 4 exhibits classify the functionalized costs into categories that vary between rate classes by an identifiable factor or allocator. In this step the costs are classified to three general cost groups based on whether they vary with volumetric demands, peak demands, or other customer specific demands. The costs are further sub-classified within these three broad categories of classification when required.

d) Tab 5 exhibits allocate the classified cost to each rate class based on allocation factors that are referenced on the exhibits.

e) Tab 6 exhibits provide rate base, working capital and net investment functionalization factors, classify transportation and storage costs and gas costs to operations, and provide cost of service allocation factors and allocation percentages.

f) Tab 7 exhibits provide functionalization and classification of costs for Tecumseh Gas. These costs are then used to charge back storage costs to Enbridge Gas Distribution's in-franchise customers and to derive ex-franchise storage rates.

REVENUE COMPARISON - CURRENT METHODOLOGY vs PROPOSED METHODOLOGY BY RATE CLASS AND COMPONENT ($000)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
		REVENUE - EB-2006-0099 RATES					(SUFFICIENCY) / DEFICIENCY					REVENUE -INTERIM EB-2006-0034 RATES				
ITEM NO.	RATE NO.	DISTRIB'TN	TRANSPORT	GAS SUPPLY LOAD BAL	GAS SUPPLY COMMODITY	TOTAL	DISTRIB'TN	TRANSPORT	GAS SUPPLY LOAD BAL	GAS SUPPLY COMMODITY	TOTAL	DISTRIB'TN	TRANSPORT	GAS SUPPLY LOAD BAL	GAS SUPPLY COMMODITY	TOTAL
1.	1	614,841	170,812	51,178	939,358	1,776,189	34,174	(2,173)	(14,691)	1,078	18,388	649,015	168,639	36,486	940,436	1,794,577
2.	6	215,881	121,277	37,790	493,868	868,817	15,453	(1,525)	(11,472)	863	3,319	231,334	119,752	26,318	494,731	872,136
3.	9	727	273	6	1,835	2,842	75	(4)	(6)	0	65	802	270	0	1,836	2,907
4.	100	54,558	51,376	14,798	74,243	194,976	8,440	(673)	(5,463)	(15)	2,288	62,998	50,703	9,335	74,228	197,264
5.	110	11,517	22,981	2,394	16,981	53,872	1,255	(301)	(1,268)	2	(311)	12,772	22,680	1,126	16,983	53,561
6.	115	8,795	27,593	1,524	14,138	52,050	1,949	(440)	(1,145)	2	365	10,744	27,153	379	14,140	52,416
7.	125	1,220	0	0	0	1,220	76	0	0	0	76	1,296	0	0	0	1,296
8.	135	783	1,454	(434)	1,777	3,580	82	(27)	(33)	(6)	17	866	1,427	(467)	1,771	3,597
9.	145	4,637	9,305	547	14,013	28,503	793	(122)	(437)	(10)	225	5,430	9,183	111	14,003	28,728
10.	170	4,086	23,821	(6,623)	19,487	40,770	1,408	(354)	(679)	3	378	5,494	23,467	(7,303)	19,490	41,148
11.	200	2,152	5,580	1,190	40,366	49,288	824	(73)	(341)	5	416	2,976	5,507	849	40,371	49,704
12.	300	150	0	0	0	150 [1]	(40)	0	0	0	(40)	110	0	0	0	110 [2]
13.	SUB-TOTAL	919,347	434,474	102,370	1,616,066	3,072,257	64,490	(5,693)	(35,535)	1,922	25,184	983,837	428,781	66,834	1,617,988	3,097,441
14.	STORAGE	1,896	0	0	0	1,896	(241)	0	0	0	(241)	1,655	0	0	0	1,655
15.	DPAC	900	0	0	0	900	660	0	0	0	660	1,560	0	0	0	1,560
16.	TOTAL	922,143	434,474	102,370	1,616,066	3,075,053	64,909	(5,693)	(35,535)	1,922	25,603	987,052	428,781	66,834	1,617,988	3,100,656

Notes:
1. Revenue based on EB-2006-0099 Rates for Rate 305
2. Revenue based on EB-2006-0034 Rate 300 Interruptible Range Rate

PROPOSED VOLUMES AND REVENUE RECOVERY BY RATE CLASS ($000)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13
		DISTRIBUTION			GAS SUPPLY TRANSPORTATION			GAS SUPPLY LOAD BALANCING			GAS SUPPLY COMMODITY			** TOTAL
ITEM NO.	RATE NO.	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	REVENUES
		10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	$000
1.	1	4,476,300	649,015	14.50	4,476,300	168,639	3.77	4,476,300	36,486	0.82	2,757,004	940,436	34.11	1,794,577
2.	6	3,142,097	231,334	7.36	3,142,097	119,752	3.81	3,142,097	26,318	0.84	1,443,468	494,731	34.27	872,136
3.	9	7,375	802	10.87	7,375	270	3.66	7,375	0	0.00	5,409	1,836	33.94	2,907
4.	100	1,387,023	62,998	4.54	1,387,023	50,703	3.66	1,387,023	9,335	0.67	218,347	74,228	34.00	197,264
5.	110	620,429	12,772	2.06	620,429	22,680	3.66	620,429	1,126	0.18	50,038	16,983	33.94	53,561
6.	115	906,196	10,744	1.19	906,196	27,153	3.00	906,196	379	0.04	41,661	14,140	33.94	52,416
7.	125	0	1,296	0.00	0	0	0.00	0	0	0.00	0	0	0.00	1,296
8.	135	55,396	866	1.56	55,396	1,427	2.58	55,396	(467)	(0.84)	5,208	1,771	34.00	3,597
9.	145	251,217	5,430	2.16	251,217	9,183	3.66	251,217	111	0.04	41,142	14,003	34.04	28,728
10.	170	729,625	5,494	0.75	729,625	23,467	3.22	729,625	(7,303)	(1.00)	57,424	19,490	33.94	41,148
11.	200	150,658	2,976	1.98	150,658	5,507	3.66	150,658	849	0.56	118,949	40,371	33.94	49,704
12.	300	31,237	110	0.00	0	0	0.00	0	0	0.00	0	0	0.00	110
13	SUB-TOTAL	11,757,552	983,837	8.37	11,726,315	428,781	3.66	11,726,315	66,834	0.57	4,738,651	1,617,988	34.14	3,097,441
14.	STORAGE	N/A	1,655	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	1,655
15.	DPAC	N/A	1,560	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	1,560
16.	TOTAL	11,757,552	987,052	8.37	11,726,315	428,781	3.66	11,726,315	66,834	0.57	4,738,651	1,617,988	34.14	3,100,656

** Total Revenue includes T-Service

FISCAL YEAR REVENUE COMPARISON - CURRENT METHODOLOGY vs PROPOSED METHODOLOGY BY RATE CLASS

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
		EB-2006-0099			INTERIM EB-2006-0034			
Item No.	Rate No.	Revenue ($000)	Unbilled Revenue ($000)	Total ($000)	Proposed Revenue ($000)	Unbilled Revenue ($000)	Total ($000)	Total Difference ($000)
1.	1	1,776,189	1,038	1,777,227	1,794,577	1,054	1,795,631	18,404
2.	6	868,817	(3,556)	865,261	872,136	(3,558)	868,578	3,317
3.	9	2,842	0	2,842	2,907	0	2,907	65
4.	100	194,976	(0)	194,976	197,264	361	197,625	2,649
5.	110	53,872	(12)	53,860	53,561	(13)	53,547	(312)
6.	115	52,050	1	52,051	52,416	1	52,416	365
7.	125	1,220	0	1,220	1,296	0	1,296	76
8.	135	3,580	0	3,580	3,597	0	3,597	17
9.	145	28,503	0	28,503	28,728	56	28,784	281
10.	170	40,770	1	40,771	41,148	1	41,148	378
11.	200	49,288	0	49,288	49,704	0	49,704	416
12.	300	150	0	150	110	0	110	(40)
13.	SUB-TOTAL	3,072,257	(2,529)	3,069,728	3,097,441	(2,099)	3,095,342	25,614
14.	STORAGE	1,896	0	1,896	1,655	0	1,655	(241)
15.	DPAC	900	0	900	1,560	0	1,560	660
16.	TOTAL	3,075,053	(2,529)	3,072,524	3,100,656	(2,099)	3,098,557	26,033

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS

Item No.	Rate No.	Col. 1	Col. 2 Rate Block m³	Col. 3 EB-2006-0099 cents *	Col. 4 Rate Change cents *	Col. 5 Interim EB-2006-0034 cents *
	RATE 1					
1.01		Customer Charge		$11.25	$0.63	$11.88
1.02		Delivery Charge	first 30	9.7581	0.5399	10.2979
1.03			next 55	9.1295	0.5051	9.6346
1.04			next 85	8.6369	0.4779	9.1148
1.05			over 170	8.2703	0.4576	8.7278
1.06		Gas Supply Load Balancing		1.1433	(0.3282)	0.8151
1.07		Gas Supply Transportation		3.8159	(0.0485)	3.7674
1.08		Gas Supply Commodity - System		34.0717	0.0391	34.1108
1.09		Gas Supply Commodity - Buy/Sell		34.0538	0.0385	34.0923
	RATE 6					
2.01		Customer Charge		$22.00	$1.58	$23.58
2.02		Delivery Charge	First 500	8.7165	0.6233	9.3398
2.03			Next 1050	6.6633	0.4765	7.1398
2.04			Next 4500	5.2260	0.3737	5.5997
2.05			Next 7000	4.3021	0.3076	4.6098
2.06			Next 15250	3.8915	0.2783	4.1697
2.07			Over 28300	3.7888	0.2709	4.0597
2.08		Gas Supply Load Balancing		1.2027	(0.3651)	0.8376
2.09		Gas Supply Transportation		3.8598	(0.0485)	3.8112
2.10		Gas Supply Commodity - System		34.2140	0.0598	34.2738
2.11		Gas Supply Commodity - Buy/Sell		34.1961	0.0591	34.2552
	RATE 9					
3.01		Customer Charge		$200.00	$20.55	$220.55
3.02		Delivery Charge	first 20000	9.0864	0.9337	10.0201
3.03			over 20000	8.5052	0.8739	9.3791
3.04		Gas Supply Load Balancing		0.0855	(0.0855)	0.0000
3.05		Gas Supply Transportation		3.7041	(0.0485)	3.6555
3.06		Gas Supply Commodity - System		33.9354	0.0044	33.9398
3.07		Gas Supply Commodity - Buy/Sell		33.9175	0.0037	33.9212
	RATE 100					
4.01		Customer Charge		$100.00	$15.10	$115.10
4.02		Demand Charge (Cents/Month/m³)		-	8.0000	8.0000
4.03		Delivery Charge	first 14,000	5.0940	(0.2695)	4.8245
4.04			next 28,000	3.7350	(0.2695)	3.4655
4.05			over 42,000	3.1760	(0.2695)	2.9065
4.06		Gas Supply Load Balancing		1.0669	(0.3939)	0.6730
4.07		Gas Supply Transportation		3.7041	(0.0485)	3.6555
4.08		Gas Supply Commodity - System		34.0023	(0.0070)	33.9953
		Gas Supply Commodity - Buy/Sell		33.9843	(0.0075)	33.9768
	RATE 110					
5.01		Customer Charge		$500.00	$54.50	$554.50
5.02		Demand Charge (Cents/Month/m³)		20.0000	2.1800	22.1800
5.03		Delivery Charge	first 1,000,000	0.4569	0.0474	0.5044
5.04			over 1,000,000	0.3069	0.0474	0.3544
5.05		Load Balancing Commodity		0.3858	(0.2043)	0.1815
5.06		Gas Supply Transportation		3.7041	(0.0485)	3.6555
5.07		Gas Supply Commodity - System		33.9354	0.0044	33.9398
5.08		Gas Supply Commodity - Buy/Sell		33.9175	0.0037	33.9212

NOTE : * Cents unless otherwise noted.

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2006-0099 cents *	Col. 4 Rate Change cents *	Col. 5 Interim EB-2006-0034 cents *
	RATE 115					
1.01		Customer Charge		$500.00	$110.78	$610.78
1.02		Demand Charge (Cents/Month/m³)		20.0000	4.4300	24.4300
1.03		Delivery Charge	first 1,000,000	0.2356	0.0374	0.2730
1.04			over 1,000,000	0.1356	0.0374	0.1730
1.05		Load Balancing Commodity		0.1682	(0.1264)	0.0418
1.06		Gas Supply Transportation		3.0449	(0.0485)	2.9964
1.07		Gas Supply Commodity - System		33.9354	0.0044	33.9398
1.08		Gas Supply Commodity - Buy/Sell		33.9175	0.0037	33.9212
	RATE 125					
2.01		Customer Charge		0.0000	$ 500.00	$ 500.00
2.02		Delivery Charge (Cents/Month/m³ of Contract Dmnd)		8.3768	0.5249	8.9017
	RATE 135	DEC - MAR				
3.00		Customer Charge		$100.00	$10.53	$110.53
3.01		Delivery Charge	first 14,000	6.5082	0.1406	6.6488
3.02			next 28,000	5.3082	0.1406	5.4488
3.03			over 42,000	4.9082	0.1406	5.0488
3.04		Gas Supply Load Balancing		0.0604	(0.0604)	0.0000
3.05		Gas Supply Transportation		2.6243	(0.0485)	2.5757
3.06		Gas Supply Commodity - System		34.1155	(0.1132)	34.0023
3.07		Gas Supply Commodity - Buy/Sell		34.0976	(0.1139)	33.9837
	RATE 135	APR - NOV				
3.08		Customer Charge		$100.00	$10.53	$110.53
3.09		Delivery Charge	first 14,000	1.8082	0.1406	1.9488
3.10			next 28,000	1.1082	0.1406	1.2488
3.11			over 42,000	0.9082	0.1406	1.0488
3.12		Gas Supply Load Balancing		0.0604	(0.0604)	0.0000
3.13		Gas Supply Transportation		2.6243	(0.0485)	2.5757
3.14		Gas Supply Commodity - System		34.1155	(0.1132)	34.0023
3.15		Gas Supply Commodity - Buy/Sell		34.0976	(0.1139)	33.9837
	RATE 145					
4.00		Customer Charge		$100.00	$17.11	$117.11
4.01		Demand Charge (Cents/Month/m³)		-	8.0000	8.0000
4.02		Delivery Charge	first 14,000	3.3237	(0.4940)	2.8296
4.03			next 28,000	1.9647	(0.4940)	1.4706
4.04			over 42,000	1.4057	(0.4940)	0.9116
4.05		Gas Supply Load Balancing		0.5923	(0.1738)	0.4185
4.06		Gas Supply Transportation		3.7041	(0.0485)	3.6555
4.07		Gas Supply Commodity - System		34.0606	(0.0243)	34.0363
4.08		Gas Supply Commodity - Buy/Sell		34.0427	(0.0250)	34.0177
	RATE 170					
5.00		Customer Charge		$200.00	$68.95	$268.95
5.01		Demand Charge (Cents/Month/m³)		3.0000	1.0300	4.0300
5.02		Delivery Charge	first 1,000,000	0.4026	0.1087	0.5113
5.03			over 1,000,000	0.2026	0.1087	0.3113
5.04		Gas Supply Load Balancing		0.2977	(0.0931)	0.2046
5.05		Gas Supply Transportation		3.2648	(0.0485)	3.2163
5.06		Gas Supply Commodity - System		33.9354	0.0044	33.9398
5.07		Gas Supply Commodity - Buy/Sell		33.9175	0.0037	33.9212

NOTE : * Cents unless otherwise noted.

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

		Col.1	Col. 2	Col. 3	Col. 4	Col. 5	
Item No.	Rate No.		Rate Block m³	EB-2006-0099 cents *	Rate Change cents *	Interim EB-2006-0034 cents *	
	RATE 200						
1.00		Customer Charge		$0.00	$0.00	$0.00	
1.01		Demand Charge (Cents/Month/m³)		10.0000	3.8300	13.8300	
1.02		Delivery Charge		0.6963	0.2666	0.9629	
1.03		Gas Supply Load Balancing		0.8713	(0.2261)	0.6452	
1.04		Gas Supply Transportation		3.7041	(0.0485)	3.6555	
1.05		Gas Supply Commodity - System		33.9354	0.0044	33.9398	
1.06		Gas Supply Commodity - Buy/Sell		33.9175	0.0037	33.9212	
	RATE 300	FIRM SERVICE					
2.00		Monthly Customer Charge		$500.00	$0.00	$500.00	
2.01		Demand Charge (Cents/Month/m³)		22.6710	1.3492	24.0202	
		INTERRUPTIBLE SERVICE					
2.02		Minimum Delivery Charge (Cents/Month/m³)		0.3630	(0.0118)	0.3512	
2.03		Maximum Delivery Charge (Cents/Month/m³)		0.8944	0.0532	0.9476	
	RATE 315						
		Monthly Customer Charge		$150.00	$0.00	$150.00	
3.00		Space Demand Chg (Cents/Month/m³)		0.0367	(0.0021)	0.0346	
3.01		Deliverability/Injection Demand Chg (Cents/Month/m³)		11.9813	0.1169	12.0982	
3.02		Injection & Withdrawal Chg (Cents/Month/m³)		0.5069	(0.0070)	0.4999	(1)
	RATE 320						
4.00		Backstop	All Gas Sold	37.7005	(0.0285)	37.6720	

NOTE : * Cents unless otherwise noted.

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

		Col.1	Col. 2	Col. 3		Col. 4	Col. 5
Item No.	Rate No.		Rate Block m³	EB-2006-0099 cents *		Change cents *	Interim EB-2006-0034 cents *
	RATE 325						
		Transmission & Compression					
1.00		Demand Charge - ATV ($/Month/10³ m³)		0.1776		(0.0124)	0.1652
1.01		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		16.0517		(1.1183)	14.9334
1.02		Commodity Charge		1.7920		(0.3196)	1.4724
		Storage					
1.03		Demand Charge - ATV ($/Month/10*3 m³)		0.2131	(2)	(0.0196)	0.1935
1.04		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		19.3327	(2)	(1.7769)	17.5558
1.05		Commodity Charge		0.7320		(0.1503)	0.5817
		(2) Note: These are UNBUNDLED Rates					
	RATE 330	Storage Service - Firm					
		Demand Charge ($/Month/10³ m³ of ATV)					
2.00		Minimum		0.3907		(0.0320)	0.3587
2.01		Maximum		1.9535		(0.1599)	1.7936
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)					
2.02		Minimum		35.3844		(2.8952)	32.4892
2.03		Maximum		176.9221		(14.4760)	162.4461
		Commodity Charge					
2.04		Minimum		2.5240		(0.4699)	2.0541
2.05		Maximum		12.6200		($2.3494)	10.2706
		Storage Service - Interruptible					
		Demand Charge ($/Month/10³ m³ of ATV)					
2.06		Minimum		0.3907		(0.0320)	0.3587
2.07		Maximum		1.9535		(0.1599)	1.7936
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)					
2.08		Minimum		28.3075		(2.3162)	25.9914
2.09		Maximum		141.5377		($11.5808)	129.9569
		Commodity Charge					
2.10		Minimum		2.5240		(0.4699)	2.0541
2.11		Maximum		12.6200		(2.3494)	10.2706
		Storage Service - Off Peak					
		Commodity Charge					
2.12		Minimum		1.0527		(0.1585)	0.8942
2.13		Maximum		42.7418		(4.6343)	38.1075
	RATE 331	Tecumseh Transmission Service					
		Firm					
		Demand Charge ($/Month/10³ m³ of					
3.00		Maximum Contracted Daily Delivery)		3.3350		1.1430	4.4780
		Interruptible					
3.01		Commodity Charge ($/10³m³ of gas delivered)		0.1320		0.0450	0.1770

NOTE : * Cents unless otherwise noted.

CALCULATION OF GAS SUPPLY CHARGES BY RATE CLASS

Item		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	REFERENCE
	DERIVATION OF GAS SUPPLY CHARGE												
	GAS SUPPLY COSTS ($000)												
1.1	Annual Commodity	1,605,938	934,354	489,194	1,833	73,998	16,958	14,119	1,765	13,943	19,461	40,312	G2 T5 S3 1.1
1.2	Bad Debt Commodity	9,700	4,715	4,821	-	121	-	-	3	40	-	-	G2 T5 S3 1.2
1.3	System Gas Fee	880	512	268	1	41	9	8	1	8	11	22	G2 T5 S3 1.1
1.4	Return on Rate Base - Working Cash	1,471	856	448	2	68	16	13	2	13	18	37	G2 T5 S2 1.1
1	Total Commodity Costs	1,617,989	940,437	494,731	1,836	74,228	16,983	14,140	1,771	14,003	19,490	40,371	
	VOLUMES (10^3 m^3)												
2.1	System and Buy/Sell Volumes	4,738,651	2,757,004	1,443,468	5,409	218,347	50,038	41,661	5,208	41,142	57,424	118,949	
2.2	System Volumes	4,738,651	2,757,004	1,443,468	5,409	218,347	50,038	41,661	5,208	41,142	57,424	118,949	
	GAS SUPPLY CHARGE SYSTEM (¢/m^3)												
3.1	Annual Commodity	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	1.1 / 2.1
3.2	Bad Debt Commodity	0.2047	0.1710	0.3340	-	0.0555	-	-	0.0624	0.0965	-	-	1.2 / 2.1
3.3	System Gas Fee	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	1.3 / 2.2
3.4	Return on Rate Base - Working Cash	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	1.4 / 2.1
3	System Gas Supply Charge	34.1445	34.1108	34.2738	33.9398	33.9953	33.9398	33.9398	34.0023	34.0363	33.9398	33.9398	
	GAS SUPPLY CHARGE BUY/SELL(¢/m3)												
4.1	Annual Commodity	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	1.1 / 2.1
4.2	Bad Debt Commodity	0.2047	0.1710	0.3340	-	0.0555	-	-	0.0624	0.0965	-	-	1.2 / 2.1
4.3	Return on Rate Base - Working Cash	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	1.4 / 2.1
4	Buy/Sell Gas Supply Charge	34.1259	34.0923	34.2552	33.9212	33.9768	33.9212	33.9212	33.9837	34.0177	33.9212	33.9212	

CALCULATION OF GAS SUPPLY LOAD BALANCING & TRANSPORTATION CHARGES BY RATE CLASS

Item		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	REFERENCE
	DERIVATION OF LOAD BALANCING CHARGES												
	ANNUAL LOAD BALANCING COSTS ($000)												
5.1	Peak	17,498	8,618	6,381	-	2,124	128	18	-	-	-	229	G2 T5 S3 2.1
5.2	Seasonal	6,808	3,180	2,275	-	823	114	41	-	120	170	85	G2 T5 S3 2.2
5.3	Return on Rate Base - Gas in Inventory	52,855	24,688	17,664	-	6,388	884	320	-	931	1,322	658	G2 T5 S2 2.2
5	Total Load Balancing	77,161	36,486	26,319	-	9,334	1,126	379	-	1,051	1,493	972	
	VOLUMES (10^3 m^3)												
6.1	Annual Deliveries	11,726,315	4,476,300	3,142,097	7,375	1,387,023	620,429	906,196	55,396	251,217	729,625	150,658	G2 T6 S3, 1.3
7	**ANNUAL LOAD BALANCING CHARGE (¢/m3)** Load Balancing		0.8151	0.8376	-	0.6730	0.1815	0.0418	-	0.4185	0.2046	0.6452	5.0 / 6
	DERIVATION OF TRANSPORTATION CHARGES												
	VOLUMES (10^3 m^3)												
6.1	Annual Deliveries	11,726,315	4,476,300	3,142,097	7,375	1,387,023	620,429	906,196	55,396	251,217	729,625	150,658	G2 T6 S3, 1.3
7.1	EB-2005-0524 Transportation Charge (¢/m^3)		3.8159	3.8598	3.7041	3.7041	3.7041	3.0449	2.6243	3.7041	3.2648	3.7041	
7.2	Increase/(Decrease) in Unit Rate		(0.0485)	(0.0485)	(0.0485)	(0.0485)	(0.0485)	(0.0485)	(0.0485)	(0.0485)	(0.0485)	(0.0485)	
7	**PROPOSED TRANSPORTATION CHARGE (¢/m^3)**		3.7674	3.8112	3.6555	3.6555	3.6555	2.9964	2.5757	3.6555	3.2163	3.6555	

CALCULATION OF SEASONAL CREDIT FOR RATE 135, 145, 170 & 200

			Reference
RATE 135			
Seasonal Credits Applicable to Rate 135	**$**	**(467)**	G2T5S3 line 3.3
Annual Volume (103 m3)		55,396	
Mean Daily Volume (103 m3)		152	
Annual Seasonal Credits	$	(3.08)	
Payable from December to March	$	(0.77)	
RATE 145			
Seasonal Credits Applicable to Rate 145	**$**	**(940)**	G2T5S3 line 2.4
Annual Volume (103 m3)		251,217	
Mean Daily Volume (103 m3)			
16 Hours		406	
72 Hours		287	
Annual Seasonal Credits			
16 Hours	$	(2.00)	
Payable from December to March	$	(0.50)	
72 Hours	$	(0.45)	
Payable from December to March	$	(0.11)	
Seasonal Credits Applicable to Rate 145			
16 Hours	$	(811.12)	
72 Hours	$	(129.36)	
RATE 170			
Seasonal Credits Applicable to Rate 170	**$**	**(8,795)**	G2T5S3 line 2.4
Annual Volume (103 m3)		729,625	
Mean Daily Volume (103 m3)		1,999	
Annual Seasonal Credits	$	(4.40)	
Payable from December to March	$	(1.10)	
RATE 200			
Seasonal Credits Applicable to Rate 200	**$**	**(123)**	G2T5S3 line 2.4
Annual Volume (103 m3)		10,217	
Mean Daily Volume (103 m3)		28	
Annual Seasonal Credits	$	(4.40)	
Payable from December to March	$	(1.10)	

DETAILED REVENUE CALCULATION — EB-2006-0099 vs EB-2006-0034

Item No.		Col. 1 Rate Block m³		Col. 2 Bills & Volumes 10^3 m³	Col. 3 EB-2006-0099 Rate cents*	Col. 4 EB-2006-0099 Revenues $000	Col. 5 Rate Change cents*	Col. 6 Interim EB-2006-0034 Rate cents*	Col. 7 Interim EB-2006-0034 Revenues $000
	RATE 1								
1.1	Customer Charge	Bills		20,055,803	$11.25	225,628	$0.63	$11.88	238,263
1.2	Delivery Charge	first	30	573,680	9.7581	55,980	0.5399	10.2979	59,077
1.3		next	55	838,570	9.1295	76,557	0.5051	9.6346	80,793
1.4		next	85	920,584	8.6369	79,510	0.4779	9.1148	83,909
1.5		over	170	2,143,465	8.2703	177,270	0.4576	8.7278	187,078
1.	Total Distribution Charge			4,476,300		614,946			649,121
2.1	Gas Supply Load Balancing			4,476,300	1.1433	51,178	(0.3282)	0.8151	36,486
2.2	Gas Supply Transportation			4,476,300	3.8159	170,812	(0.0485)	3.7674	168,639
3.1	Gas Supply Commodity - System			2,757,004	34.0717	939,358	0.0391	34.1108	940,436
3.2	Gas Supply Commodity - Buy/Sell			0	34.0538	0	0.0385	34.0923	0
3.	Total Gas Supply Charge			2,757,004		939,358			940,436
4.1	TOTAL DISTRIBUTION			4,476,300		614,946			649,121
4.2	TOTAL GAS SUPPLY LOAD BALANCINC			4,476,300		221,990			205,126
4.3	TOTAL GAS SUPPLY COMMODITY			2,757,004		939,358			940,436
4.	TOTAL RATE 1			**4,476,300**		1,776,294			1,794,682
5.	Adj. Factor	0.9999							
6.	ADJUSTED REVENUE					**1,776,189**			**1,794,577**
7.	REVENUE INC./(DEC.)								**18,388**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION — EB-2006-0099 vs EB-2006-0034

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
				EB-2006-0099			Interim EB-2006-0034	
Item No.		Rate Block m³	Bills & Volumes 10³ m³	Rate cents*	Revenues $000	Rate Change cents*	Rate cents*	Revenues $000
	RATE 6							
1.1	Customer Charge	Bills	1,791,821	$22.00	39,420	$1.58	$23.58	42,251
1.2	Delivery Charge	First 500	498,786	8.7165	43,476	0.6233	9.3398	46,585
1.3		Next 1050	569,298	6.6633	37,934	0.4765	7.1398	40,647
1.4		Next 4500	938,975	5.2260	49,071	0.3737	5.5997	52,580
1.5		Next 7000	516,778	4.3021	22,232	0.3076	4.6098	23,822
1.6		Next 15250	364,527	3.8915	14,185	0.2783	4.1697	15,200
1.7		Over 28300	253,733	3.7888	9,613	0.2709	4.0597	10,301
1.	Total Distribution Charge		3,142,097		215,933			231,386
2.1	Gas Supply Load Balancing		3,142,097	1.2027	37,790	(0.3651)	0.8376	26,318
2.2	Gas Supply Transportation		3,142,097	3.8598	121,277	(0.0485)	3.8112	119,752
3.1	Gas Supply Commodity - System		1,443,468	34.2140	493,868	0.0598	34.2738	494,731
3.2	Gas Supply Commodity - Buy/Sell		0	34.1961	0	0.0591	34.2552	0
3.	Total Gas Supply Charge		1,443,468		493,868			494,731
4.1	TOTAL DISTRIBUTION		3,142,097		215,933			231,386
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		3,142,097		159,067			146,070
4.3	TOTAL GAS SUPPLY COMMODITY		1,443,468		493,868			494,731
4.	TOTAL RATE 6		**3,142,097**		868,868			872,187
5.	Adj. Factor	1.000						
6.	ADJUSTED REVENUE				**868,817**			**872,136**
7.	REVENUE INC./(DEC.)							**3,319**

NOTE * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION   EB-2006-0099 vs EB-2006-0034

Item No.		Rate Block m³ (Col. 1)	Bills & Volumes 10^3 m³ (Col. 2)	EB-2006-0099 Rate cents* (Col. 3)	EB-2006-0099 Revenues $000 (Col. 4)	Rate Change cents* (Col. 5)	Interim EB-2006-0034 Rate cents* (Col. 6)	Interim EB-2006-0034 Revenues $000 (Col. 7)
	RATE 9							
1.1	Customer Charge	Bills	384	$200.00	77	$20.55	$220.55	85
1.2	Delivery Charge	first 20000	3,945	9.0864	358	0.9337	10.0201	395
1.3		over 20000	3,430	8.5052	292	0.8739	9.3791	322
1.	Total Distribution Charge		7,375		727			802
2.1	Gas Supply Load Balancing		7,375	0.0855	6	(0.0855)	0.0000	0
2.2	Gas Supply Transportation		7,375	3.7041	273	(0.0485)	3.6555	270
3.1	Gas Supply Commodity - System		5,409	33.9354	1,835	0.0044	33.9398	1,836
3.2	Gas Supply Commodity - Buy/Sell		0	33.9175	0	0.0037	33.9212	0
3.	Total Gas Supply Charge		5,409		1,835			1,836
4.1	TOTAL DISTRIBUTION		7,375		727			802
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		7,375		279			270
4.3	TOTAL GAS SUPPLY COMMODITY		5,409		1,835			1,836
4	TOTAL RATE 9		**7,375**		**2,842**			**2,907**
5.	REVENUE INC./(DEC.)							**65**

		Rate Block m³	Contracts & Volumes 10^3 m³	EB-2006-0099 Rate cents*	EB-2006-0099 Revenues $000	Rate Change cents*	Interim EB-2006-0034 Rate cents*	Interim EB-2006-0034 Revenues $000
	RATE 100							
1.1	Customer Charge	Contracts	23,340	$100.00	2,334	$15.10	$115.10	2,686
1.2	Demand Charge		147,823	$0.00	0	8.00	8.00	11,826
1.3	Delivery Charge	first 14,000	301,761	5.0940	15,372	(0.2695)	4.8245	14,558
1.4		next 28,000	426,590	3.7350	15,933	(0.2695)	3.4655	14,783
1.5		over 42,000	658,672	3.1760	20,919	(0.2695)	2.9065	19,144
1	Total Distribution Charge		1,387,023		54,558			62,998
2.1	Gas Supply Load Balancing		1,387,023	1.0669	14,798	(0.3939)	0.6730	9,335
2.2	Gas Supply Transportation		1,387,023	3.7041	51,376	(0.0485)	3.6555	50,703
3.1	Gas Supply Commodity - System		218,347	34.0023	74,243	(0.0070)	33.9953	74,228
3.2	Gas Supply Commodity - Buy/Sell		0	33.9843	0	(0.0075)	33.9768	0
3	Total Gas Supply Charge		218,347		74,243			74,228
4.1	TOTAL DISTRIBUTION		1,387,023		54,558			62,998
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		1,387,023		66,174			60,038
4.3	TOTAL GAS SUPPLY COMMODITY		218,347		74,243			74,228
4	TOTAL RATE 100		**1,387,023**		**194,976**			**197,264**
5	REVENUE INC./(DEC.)							**2,288**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION — EB-2006-0099 vs EB-2006-0034

Item No.		Rate Block m³ (Col. 1)	Contracts & Volumes 10³ m³ (Col. 2)	EB-2006-0099 Rate cents* (Col. 3)	EB-2006-0099 Revenues $000 (Col. 4)	Rate Change cents* (Col. 5)	Interim EB-2006-0034 Rate cents* (Col. 6)	Interim EB-2006-0034 Revenues $000 (Col. 7)
	RATE 110							
1.1	Customer Charge	Contracts	3,264	$500.00	1,632	$54.50	$554.50	1,810
1.2	Demand Charge		35,929	20.0000	7,186	2.1800	22.1800	7,969
1.3	Delivery Charge	first 1,000,000	529,548	0.4569	2,420	0.0474	0.5044	2,671
1.4		over 1,000,000	90,881	0.3069	279	0.0474	0.3544	322
1.	Total Distribution Charge		620,429		11,516			12,772
2.1	Load Balancing Demand		35,929	0.0000	0	0.0000	0.0000	0
2.2	Load Balancing Commodity		620,429	0.3858	2,394	(0.2043)	0.1815	1,126
2.3	Gas Supply Transportation		620,429	3.7041	22,981	(0.0485)	3.6555	22,680
2.	Total Gas Supply Load Balancing				25,375			23,806
3.1	Gas Supply Commodity - System		50,038	33.9354	16,981	0.0044	33.9398	16,983
3.2	Gas Supply Commodity - Buy/Sell		0	33.9175	0	0.0037	33.9212	0
3.	Total Gas Supply Charge		50,038		16,981			16,983
4.1	TOTAL DISTRIBUTION		620,429		11,516			12,772
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		620,429		25,375			23,806
4.3	TOTAL GAS SUPPLY COMMODITY		50,038		16,981			16,983
4.	TOTAL RATE 110		**620,429**		**53,872**			**53,561**
5.	REVENUE INC./(DEC.)							**(311)**

Item No.		Rate Block m³	Contracts & Volumes 10³ m³	EB-2006-0099 Rate cents*	EB-2006-0099 Revenues $000	Rate Change cents*	Interim EB-2006-0034 Rate cents*	Interim EB-2006-0034 Revenues $000
	RATE 115							
6.6	Customer Charge	Contracts	608	$500.00	304	$110.78	$610.78	371
6.2	Demand Charge		34,811	20.0000	6,962	4.4300	24.4300	8,504
6.3	Delivery Charge	first 1,000,000	300,110	0.2356	707	0.0374	0.2730	819
6.4		over 1,000,000	606,085	0.1356	822	0.0374	0.1730	1,049
6	Total Distribution Charge		906,196		8,795			10,744
7.1	Load Balancing Demand		34,811	0.0000	0	0.0000	0.0000	0
7.7	Load Balancing Commodity		906,196	0.1682	1,524	(0.1264)	0.0418	379
7.3	Gas Supply Transportation		906,196	3.0449	27,593	(0.0485)	2.9964	27,153
7	Total Gas Supply Load Balancing				29,117			27,532
8.1	Gas Supply Commodity - System		41,661	33.9354	14,138	0.0044	33.9398	14,140
8.2	Gas Supply Commodity - Buy/Sell		0	33.9175	0	0.0037	33.9212	0
8.	Total Gas Supply Charge		41,661		14,138			14,140
9.1	TOTAL DISTRIBUTION		906,196		8,795			10,744
9.2	TOTAL GAS SUPPLY LOAD BALANCIN		906,196		29,117			27,532
9.3	TOTAL GAS SUPPLY COMMODITY		41,661		14,138			14,140
9.	TOTAL RATE 115		**906,196**		**52,050**			**52,415**
10.	REVENUE INC./(DEC.)							**365**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION — EB-2006-0099 vs EB-2006-0034

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Item No.		Rate Block m³	Contracts & Volumes 10^3 m³	EB-2006-0099 Rate cents*	EB-2006-0099 Revenues $000	Rate Change cents*	Interim EB-2006-0034 Rate cents*	Interim EB-2006-0034 Revenues $000
	RATE 125							
1.1	Customer Charge		5	$ -	0	$ 500.00	$ 500.00	3
1.2	Demand Charge		14,560	8.3768	1,220	0.5249	8.9017	1,296
1.	Total Distribution Charge		14,560		1,220			1,296

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Item No.		Rate Block m³	Contracts & Volumes 10^3 m³	EB-2006-0099 Rate cents*	EB-2006-0099 Revenues $000	Rate Change cents*	Interim EB-2006-0034 Rate cents*	Interim EB-2006-0034 Revenues $000
	RATE 135							
	DEC to MAR							
1.1	Customer Charge	Contracts	144	$100.00	14	$10.53	$110.53	16
1.2	Delivery Charge	first 14,000	615	6.5082	40	0.1406	6.6488	41
1.3		next 28,000	996	5.3082	53	0.1406	5.4488	54
1.4		over 42,000	2,741	4.9082	135	0.1406	5.0488	138
1.	Total Distribution Charge		4,352		242			249
2.1	Gas Supply Load Balancing		4,352	0.0604	3	(0.0604)	0.0000	0
2.2	Gas Supply Transportation		4,352	2.6243	114	(0.0485)	2.5757	112
2.3	Seasonal Credit				(467)			(467)
3.1	Gas Supply Commodity - System		134	34.1155	46	(0.1132)	34.0023	46
3.2	Gas Supply Commodity - Buy/Sell		0	34.0976	0	(0.1139)	33.9837	0
3.	Total Gas Supply Charge		134		46			46
4.	SUB-TOTAL WINTER				-63			-60
	APR to NOV							
5.1	Customer Charge	Contracts	288	$100.00	29	$10.53	$110.53	32
5.2	Delivery Charge	first 14,000	3,812	1.8082	69	0.1406	1.9488	74
5.3		next 28,000	7,370	1.1082	82	0.1406	1.2488	92
5.4		over 42,000	39,861	0.9082	362	0.1406	1.0488	418
5.	Total Distribution Charge		51,044		541			616
6.1	Gas Supply Load Balancing		51,044	0.0604	31	(0.0604)	0.0000	0
6.2	Gas Supply Transportation		51,044	2.6243	1,340	(0.0485)	2.5757	1,315
7.1	Gas Supply Commodity - System		5,074	34.1155	1,731	(0.1132)	34.0023	1,725
7.2	Gas Supply Commodity - Buy/Sell		0	34.0976	0	(0.1139)	33.9837	0
7.	Total Gas Supply Charge		5,074		1,731			1,725
8.	SUB-TOTAL SUMMER				3,643			3,656
9.1	TOTAL DISTRIBUTION		55,396		783			866
9.2	TOTAL GAS SUPPLY LOAD BALANCINC		55,396		1,020			960
9.3	TOTAL GAS SUPPLY COMMODITY		5,208		1,777			1,771
9.	TOTAL RATE 135		**55,396**		**3,580**			**3,597**
10.	REVENUE INC./(DEC.)							**17**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION EB-2006-0099 vs EB-2006-0034

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
				EB-2006-0099			Interim EB-2006-0034	
Item No.		Rate Block m³	Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000	Rate Change cents*	Rate cents*	Revenues $000
	RATE 145							
1.1	Customer Charge	Contracts	2,316	$100.00	232	$17.11	$117.11	271
1.2	Demand Charge		24,934	-	0	8.00	8.0000	1,995
1.2	Delivery Charge	first 14,000	30,526	3.3237	1,015	(0.4940)	2.8296	864
1.3		next 28,000	51,632	1.9647	1,014	(0.4940)	1.4706	759
1.4		over 42,000	169,059	1.4057	2,376	(0.4940)	0.9116	1,541
1.	Total Distribution Charge		251,217		4,637			5,430
2.1	Gas Supply Load Balancing		251,217	0.5923	1,488	(0.1738)	0.4185	1,051
2.2	Gas Supply Transportation		251,217	3.7041	9,305	(0.0485)	3.6555	9,183
2.3	Curtailment Credit				(940)			(940)
3.1	Gas Supply Commodity - System		41,142	34.0606	14,013	(0.0243)	34.0363	14,003
3.2	Gas Supply Commodity - Buy/Sell		0	34.0427	0	(0.0250)	34.0177	0
3.	Total Gas Supply Charge		41,142		14,013			14,003
4.1	TOTAL DISTRIBUTION		251,217		4,637			5,430
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		251,217		9,853			9,294
4.3	TOTAL GAS SUPPLY COMMODITY		41,142		14,013			14,003
4.	TOTAL RATE 145		**251,217**		**28,503**			**28,728**
5.	REVENUE INC./(DEC.)							**225**

				EB-2006-0099			Interim EB-2006-0034	
		Rate Block m³	Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000	Rate Change cents*	Rate cents*	Revenues $000
	RATE 170							
6.6	Customer Charge	Contracts	522	$200.00	104	$68.95	$268.95	140
6.2	Demand Charge		56,003	3.0000	1,680	1.0300	4.0300	2,257
6.3	Delivery Charge	first 1,000,000	411,401	0.4026	1,656	0.1087	0.5113	2,104
6.4		over 1,000,000	318,224	0.2026	645	0.1087	0.3113	991
6	Total Distribution Charge		729,625		4,086			5,492
7.1	Gas Supply Load Balancing		729,625	0.2977	2,172	(0.0931)	0.2046	1,493
7.7	Gas Supply Transportation		729,625	3.2648	23,821	(0.0485)	3.2163	23,467
7.3	Curtailment Credit				(8,795)			(8,795)
8.1	Gas Supply Commodity - System		57,424	33.9354	19,487	0.0044	33.9398	19,490
8.2	Gas Supply Commodity - Buy/Sell		0	33.9175	0	0.0037	33.9212	0
8.	Total Gas Supply Charge		57,424		19,487			19,490
9.1	TOTAL DISTRIBUTION		729,625		4,086			5,492
9.2	TOTAL GAS SUPPLY LOAD BALANCIN		729,625		17,198			16,164
9.3	TOTAL GAS SUPPLY COMMODITY		57,424		19,487			19,490
9.	TOTAL RATE 170		**729,625**		**40,770**			**41,145**
10.	REVENUE INC./(DEC.)							**375**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION EB-2006-0099 vs EB-2006-0034

Item No.		Rate Block m³ (Col. 1)	Contracts & Volumes 10³ m³ (Col. 2)	EB-2006-0099 Rate cents* (Col. 3)	EB-2006-0099 Revenues $000 (Col. 4)	Rate Change cents* (Col. 5)	Interim EB-2006-0034 Rate cents* (Col. 6)	Interim EB-2006-0034 Revenues $000 (Col. 7)
	RATE 200							
1.1	Customer Charge	Contracts	12	$0.00	0	$0.00	$0.00	0
1.2	Demand Charge		11,032	10.0000	1,103	3.8300	13.8300	1,526
1.3	Delivery Charge		150,658	0.6963	1,049	0.2666	0.9629	1,451
1.	Total Distribution Charge		150,658		2,152			2,976
2.1	Gas Supply Load Balancing		150,658	0.8713	1,313	(0.2261)	0.6452	972
2.2	Gas Supply Transportation		150,658	3.7041	5,580	(0.0485)	3.6555	5,507
2.3	Curtailment Credit				(123)			(123)
3.1	Gas Supply Commodity - System		118,949	33.9354	40,366	0.0044	33.9398	40,371
3.2	Gas Supply Commodity - Buy/Sell		0	33.9175	0	0.0037	33.9212	0
3.	Total Gas Supply Charge		118,949		40,366			40,371
4.1	TOTAL DISTRIBUTION		150,658		2,152			2,976
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		150,658		6,770			6,356
4.3	TOTAL GAS SUPPLY COMMODITY		118,949		40,366			40,371
4.	TOTAL RATE 200		**150,658**		**49,288**			**49,704**
5.	REVENUE INC./(DEC.)							**416**

Item No.		Rate Block m³	Contracts & Volumes 10³ m³	EB-2006-0099 Rate cents*	EB-2006-0099 Revenues $000	Rate Change cents*	Interim EB-2006-0034 Rate cents*	Interim EB-2006-0034 Revenues $000
	RATE 300							
	Firm							
	Customer Charge		0		0	500.0000	$500.00	0
	Demand Charge		0		0	24.0202	24.0202	0
	Interruptible							
	Minimum Delivery Charge		31,237		150 [1]	0.3512	0.3512	110
	Maximum Delivery Charge		0		0	0.9476	0.9476	0
8.	TOTAL RATE 300 CDS		**0**		**150**			**110**
9.	REVENUE INC./(DEC.)							**(40)**

NOTE: * Cents unless otherwise noted.
1. Existing Rate 300 revenue is calculated using 2006 July QRAM Rate 305

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating & Water Htg.				**Heating, Water Htg. & Other Uses**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	3,064	3,064	0	0.0%	4,691	4,691	0	0.0%
1.2	CUSTOMER CHG.	$	142.56	135.00	7.56	5.6%	142.56	135.00	7.56	5.6%
1.3	DISTRIBUTION CHG.	$	281.41	266.66	14.75	5.5%	424.20	401.94	22.26	5.5%
1.4	LOAD BALANCING	§ $	140.39	151.93	(11.54)	-7.6%	214.96	232.63	(17.67)	-7.6%
1.5	SALES COMMDTY	$	1,045.16	1,043.95	1.21	0.1%	1,600.14	1,598.30	1.84	0.1%
1.6	TOTAL SALES	$	1,609.52	1,597.54	11.98	0.7%	2,381.86	2,367.87	13.99	0.6%
1.7	TOTAL T-SERVICE	$	564.36	553.59	10.77	1.9%	781.72	769.57	12.15	1.6%
1.8	SALES UNIT RATE	$/m³	0.5253	0.5214	0.0039	0.7%	0.5078	0.5048	0.0030	0.6%
1.9	T-SERVICE UNIT RATE	$/m³	0.1842	0.1807	0.0035	1.9%	0.1666	0.1641	0.0026	1.6%
1.10	SALES UNIT RATE	$/GJ	13.937	13.834	0.1037	0.7%	13.472	13.393	0.0791	0.6%
1.11	T-SERVICE UNIT RATE	$/GJ	4.887	4.794	0.0933	1.9%	4.421	4.353	0.0687	1.6%

Item No.			**Heating Only**				**Heating & Water Htg.**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	1,955	1,955	0	0.0%	2,005	2,005	0	0.0%
2.2	CUSTOMER CHG.	$	142.56	135.00	7.56	5.6%	142.56	135.00	7.56	5.6%
2.3	DISTRIBUTION CHG.	$	180.50	171.03	9.47	5.5%	187.85	177.98	9.87	5.5%
2.4	LOAD BALANCING	§ $	89.59	96.95	(7.36)	-7.6%	91.87	99.43	(7.56)	-7.6%
2.5	SALES COMMDTY	$	666.87	666.09	0.78	0.1%	683.92	683.13	0.79	0.1%
2.6	TOTAL SALES	$	1,079.52	1,069.07	10.45	1.0%	1,106.20	1,095.54	10.66	1.0%
2.7	TOTAL T-SERVICE	$	412.65	402.98	9.67	2.4%	422.28	412.41	9.87	2.4%
2.8	SALES UNIT RATE	$/m³	0.5522	0.5468	0.0053	1.0%	0.5517	0.5464	0.0053	1.0%
2.9	T-SERVICE UNIT RATE	$/m³	0.2111	0.2061	0.0049	2.4%	0.2106	0.2057	0.0049	2.4%
2.10	SALES UNIT RATE	$/GJ	14.651	14.509	0.1418	1.0%	14.638	14.497	0.1411	1.0%
2.11	T-SERVICE UNIT RATE	$/GJ	5.600	5.469	0.1312	2.4%	5.588	5.457	0.1306	2.4%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				General & Water Htg.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m³	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	142.56	135.00	7.56	5.6%	142.56	135.00	7.56	5.6%
3.3	DISTRIBUTION CHG.	$	456.23	432.24	23.99	5.6%	106.06	100.50	5.56	5.5%
3.4	LOAD BALANCING	§ $	231.33	250.36	(19.03)	-7.6%	49.55	53.61	(4.06)	-7.6%
3.5	SALES COMMDTY	$	1,721.90	1,719.95	1.95	0.1%	368.74	368.31	0.43	0.1%
3.6	TOTAL SALES	$	2,552.02	2,537.55	14.47	0.6%	666.91	657.42	9.49	1.4%
3.7	TOTAL T-SERVICE	$	830.12	817.60	12.52	1.5%	298.17	289.11	9.06	3.1%
3.8	SALES UNIT RATE	$/m³	0.5056	0.5027	0.0029	0.6%	0.6169	0.6082	0.0088	1.4%
3.9	T-SERVICE UNIT RATE	$/m³	0.1644	0.1620	0.0025	1.5%	0.2758	0.2674	0.0084	3.1%
3.10	SALES UNIT RATE	$/GJ	13.413	13.337	0.0761	0.6%	16.369	16.136	0.2329	1.4%
3.11	T-SERVICE UNIT RATE	$/GJ	4.363	4.297	0.0658	1.5%	7.318	7.096	0.2224	3.1%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Commercial Heating & Other Uses				Com. Htg., Air Cond'ng & Other Uses			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	282.96	264.00	18.96	7.2%	282.96	264.00	18.96	7.2%
1.3	DISTRIBUTION CHG.	$	1,597.92	1,491.16	106.76	7.2%	2,050.21	1,913.24	136.97	7.2%
1.4	LOAD BALANCING	§ $	1,050.91	1,144.41	(93.50)	-8.2%	1,361.09	1,482.19	(121.10)	-8.2%
1.5	SALES COMMDTY	$	7,747.94	7,734.42	13.52	0.2%	10,034.67	10,017.15	17.52	0.2%
1.6	TOTAL SALES	$	10,679.73	10,633.99	45.74	0.4%	13,728.93	13,676.58	52.35	0.4%
1.7	TOTAL T-SERVICE	$	2,931.79	2,899.57	32.22	1.1%	3,694.26	3,659.43	34.83	1.0%
1.8	SALES UNIT RATE	$/m³	0.4724	0.4704	0.0020	0.4%	0.4689	0.4671	0.0018	0.4%
1.9	T-SERVICE UNIT RATE	$/m³	0.1297	0.1283	0.0014	1.1%	0.1262	0.1250	0.0012	1.0%
1.10	SALES UNIT RATE	$/GJ	12.535	12.481	0.0537	0.4%	12.441	12.394	0.0474	0.4%
1.11	T-SERVICE UNIT RATE	$/GJ	3.441	3.403	0.0378	1.1%	3.348	3.316	0.0316	1.0%

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Medium Commercial Customer				Large Commercial Customer			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	282.96	264.00	18.96	7.2%	282.96	264.00	18.96	7.2%
2.3	DISTRIBUTION CHG.	$	8,605.13	8,030.38	574.75	7.2%	15,755.58	14,703.30	1,052.28	7.2%
2.4	LOAD BALANCING	§ $	7,882.67	8,584.06	(701.39)	-8.2%	15,765.29	17,168.06	(1,402.77)	-8.2%
2.5	SALES COMMDTY	$	58,115.68	58,014.31	101.37	0.2%	116,231.02	116,028.24	202.78	0.2%
2.6	TOTAL SALES	$	74,886.44	74,892.75	(6.31)	0.0%	148,034.85	148,163.60	(128.75)	-0.1%
2.7	TOTAL T-SERVICE	$	16,770.76	16,878.44	(107.68)	-0.6%	31,803.83	32,135.36	(331.53)	-1.0%
2.8	SALES UNIT RATE	$/m³	0.4416	0.4417	(0.0000)	0.0%	0.4365	0.4369	(0.0004)	-0.1%
2.9	T-SERVICE UNIT RATE	$/m³	0.0989	0.0995	(0.0006)	-0.6%	0.0938	0.0948	(0.0010)	-1.0%
2.10	SALES UNIT RATE	$/GJ	11.718	11.719	(0.0010)	0.0%	11.582	11.592	(0.0101)	-0.1%
2.11	T-SERVICE UNIT RATE	$/GJ	2.624	2.641	(0.0168)	-0.6%	2.488	2.514	(0.0259)	-1.0%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Industrial General Use				**Industrial Heating & Other Uses**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	43,285	43,285	0	0.0%	63,903	63,903	0	0.0%
3.2	CUSTOMER CHG.	$	282.96	264.00	18.96	7.2%	282.96	264.00	18.96	7.2%
3.3	DISTRIBUTION CHG.	$	2,832.89	2,643.66	189.23	7.2%	3,799.49	3,545.72	253.77	7.2%
3.4	LOAD BALANCING	§ $	2,012.23	2,191.27	(179.04)	-8.2%	2,970.73	3,235.07	(264.34)	-8.2%
3.5	SALES COMMDTY	$	14,835.42	14,809.52	25.90	0.2%	21,901.98	21,863.79	38.19	0.2%
3.6	TOTAL SALES	$	19,963.50	19,908.45	55.05	0.3%	28,955.16	28,908.58	46.58	0.2%
3.7	TOTAL T-SERVICE	$	5,128.08	5,098.93	29.15	0.6%	7,053.18	7,044.79	8.39	0.1%
3.8	SALES UNIT RATE	$/m³	0.4612	0.4599	0.0013	0.3%	0.4531	0.4524	0.0007	0.2%
3.9	T-SERVICE UNIT RATE	$/m³	0.1185	0.1178	0.0007	0.6%	0.1104	0.1102	0.0001	0.1%
3.10	SALES UNIT RATE	$/GJ	12.237	12.203	0.0337	0.3%	12.022	12.003	0.0193	0.2%
3.11	T-SERVICE UNIT RATE	$/GJ	3.143	3.125	0.0179	0.6%	2.928	2.925	0.0035	0.1%

			Medium Industrial Customer				**Large Industrial Customer**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
4.1	VOLUME	m³	169,563	169,563	0	0.0%	339,124	339,124	0	0.0%
4.2	CUSTOMER CHG.	$	282.96	264.00	18.96	7.2%	282.96	264.00	18.96	7.2%
4.3	DISTRIBUTION CHG.	$	8,812.11	8,223.60	588.51	7.2%	15,909.36	14,846.84	1,062.52	7.2%
4.4	LOAD BALANCING	§ $	7,882.69	8,584.06	(701.37)	-8.2%	15,765.24	17,168.01	(1,402.77)	-8.2%
4.5	SALES COMMDTY	$	58,115.69	58,014.29	101.40	0.2%	116,230.69	116,027.89	202.80	0.2%
4.6	TOTAL SALES	$	75,093.45	75,085.95	7.50	0.0%	148,188.25	148,306.74	(118.49)	-0.1%
4.7	TOTAL T-SERVICE	$	16,977.76	17,071.66	(93.90)	-0.6%	31,957.56	32,278.85	(321.29)	-1.0%
4.8	SALES UNIT RATE	$/m³	0.4429	0.4428	0.0000	0.0%	0.4370	0.4373	(0.0003)	-0.1%
4.9	T-SERVICE UNIT RATE	$/m³	0.1001	0.1007	(0.0006)	-0.6%	0.0942	0.0952	(0.0009)	-1.0%
4.10	SALES UNIT RATE	$/GJ	11.750	11.749	0.0012	0.0%	11.594	11.603	(0.0093)	-0.1%
4.11	T-SERVICE UNIT RATE	$/GJ	2.657	2.671	(0.0147)	-0.6%	2.500	2.525	(0.0251)	-1.0%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				**Rate 100 - Average Commercial Firm**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
1.2	CUSTOMER CHG.	$	1,381.20	1,200.00	181.20	15.1%	1,381.20	1,200.00	181.20	15.1%
1.3	DISTRIBUTION CHG.	$	16,548.04	14,588.90	1,959.14	13.4%	26,163.16	23,466.91	2,696.25	11.5%
1.4	LOAD BALANCING	$	14,681.81	16,182.56	(1,500.75)	-9.3%	25,909.14	28,557.46	(2,648.33)	-9.3%
1.5	SALES COMMDTY	$	115,307.98	115,331.72	(23.74)	0.0%	203,484.98	203,526.88	(41.90)	0.0%
1.6	TOTAL SALES	$	147,919.03	147,303.18	615.85	0.4%	256,938.48	256,751.25	187.22	0.1%
1.7	TOTAL T-SERVICE	$	32,611.05	31,971.46	639.59	2.0%	53,453.50	53,224.37	229.12	0.4%
1.8	SALES UNIT RATE	$/m³	0.4361	0.4343	0.0018	0.4%	0.4293	0.4289	0.0003	0.1%
1.9	T-SERVICE UNIT RATE	$/m³	0.0961	0.0943	0.0019	2.0%	0.0893	0.0889	0.0004	0.4%
1.10	SALES UNIT RATE	$/GJ	11.571	11.522	0.0482	0.4%	11.389	11.381	0.0083	0.1%
1.11	T-SERVICE UNIT RATE	$/GJ	2.551	2.501	0.0500	2.0%	2.369	2.359	0.0102	0.4%

			Rate 100 - Small Industrial Firm				**Rate 100 - Average Industrial Firm**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
2.2	CUSTOMER CHG.	$	1,381.20	1,200.00	181.20	15.1%	1,381.20	1,200.00	181.20	15.1%
2.3	DISTRIBUTION CHG.	$	16,820.85	14,861.70	1,959.15	13.2%	26,404.57	23,708.35	2,696.22	11.4%
2.4	LOAD BALANCING	$	14,681.82	16,182.54	(1,500.72)	-9.3%	25,909.10	28,557.43	(2,648.33)	-9.3%
2.5	SALES COMMDTY	$	115,307.98	115,331.72	(23.74)	0.0%	203,484.63	203,526.55	(41.92)	0.0%
2.6	TOTAL SALES	$	148,191.85	147,575.96	615.89	0.4%	257,179.50	256,992.33	187.17	0.1%
2.7	TOTAL T-SERVICE	$	32,883.87	32,244.24	639.63	2.0%	53,694.87	53,465.78	229.09	0.4%
2.8	SALES UNIT RATE	$/m³	0.4369	0.4351	0.0018	0.4%	0.4297	0.4293	0.0003	0.1%
2.9	T-SERVICE UNIT RATE	$/m³	0.0969	0.0951	0.0019	2.0%	0.0897	0.0893	0.0004	0.4%
2.10	SALES UNIT RATE	$/GJ	11.592	11.544	0.0482	0.4%	11.400	11.392	0.0083	0.1%
2.11	T-SERVICE UNIT RATE	$/GJ	2.572	2.522	0.0500	2.0%	2.380	2.370	0.0102	0.4%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 145 - Small Commercial Interr.				Rate 145 - Average Commercial Interr.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
3.2	CUSTOMER CHG.	$	1,405.32	1,200.00	205.32	17.1%	1,405.32	1,200.00	205.32	17.1%
3.3	DISTRIBUTION CHG.	$	9,781.66	8,584.07	1,197.59	14.0%	14,222.48	12,870.12	1,352.36	10.5%
3.4	LOAD BALANCING	$	11,958.70	12,712.05	(753.35)	-5.9%	21,103.93	22,434.69	(1,330.76)	-5.9%
3.5	SALES COMMDTY	$	115,447.05	115,529.46	(82.41)	-0.1%	203,730.40	203,875.87	(145.47)	-0.1%
3.6	TOTAL SALES	$	138,592.73	138,025.58	567.15	0.4%	240,462.13	240,380.68	81.45	0.0%
3.7	TOTAL T-SERVICE	$	23,145.68	22,496.12	649.56	2.9%	36,731.73	36,504.81	226.92	0.6%
3.8	SALES UNIT RATE	$/m³	0.4086	0.4069	0.0017	0.4%	0.4017	0.4016	0.0001	0.0%
3.9	T-SERVICE UNIT RATE	$/m³	0.0682	0.0663	0.0019	2.9%	0.0614	0.0610	0.0004	0.6%
3.10	SALES UNIT RATE	$/GJ	10.841	10.797	0.0444	0.4%	10.659	10.655	0.0036	0.0%
3.11	T-SERVICE UNIT RATE	$/GJ	1.811	1.760	0.0508	2.9%	1.628	1.618	0.0101	0.6%

Item No.			Rate 145 - Small Industrial Interr.				Rate 145 - Average Industrial Interr.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
4.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
4.2	CUSTOMER CHG.	$	1,405.32	1,200.00	205.32	17.1%	1,405.32	1,200.00	205.32	17.1%
4.3	DISTRIBUTION CHG.	$	10,054.46	8,856.86	1,197.60	13.5%	14,463.93	13,111.59	1,352.34	10.3%
4.4	LOAD BALANCING	$	11,958.71	12,712.04	(753.33)	-5.9%	21,103.89	22,434.65	(1,330.76)	-5.9%
4.5	SALES COMMDTY	$	115,447.05	115,529.47	(82.42)	-0.1%	203,730.05	203,875.50	(145.45)	-0.1%
4.6	TOTAL SALES	$	138,865.54	138,298.37	567.17	0.4%	240,703.19	240,621.74	81.45	0.0%
4.7	TOTAL T-SERVICE	$	23,418.49	22,768.90	649.59	2.9%	36,973.14	36,746.24	226.90	0.6%
4.8	SALES UNIT RATE	$/m³	0.4094	0.4077	0.0017	0.4%	0.4021	0.4020	0.0001	0.0%
4.9	T-SERVICE UNIT RATE	$/m³	0.0690	0.0671	0.0019	2.9%	0.0618	0.0614	0.0004	0.6%
4.10	SALES UNIT RATE	$/GJ	10.862	10.818	0.0444	0.4%	10.669	10.666	0.0036	0.0%
4.11	T-SERVICE UNIT RATE	$/GJ	1.832	1.781	0.0508	2.9%	1.639	1.629	0.0101	0.6%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 110 - Small Ind. Firm - 50% LF				Rate 110 - Average Ind. Firm - 50% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
5.1	VOLUME	m³	598,568	598,568	0	0.0%	9,976,121	9,976,121	0	0.0%
5.2	CUSTOMER CHG.	$	6,654.00	6,000.00	654.00	10.9%	6,654.00	6,000.00	654.00	10.9%
5.3	DISTRIBUTION CHG.	$	11,781.13	10,635.90	1,145.23	10.8%	192,663.39	173,837.81	18,825.58	10.8%
5.4	LOAD BALANCING	$	22,967.18	24,480.64	(1,513.46)	-6.2%	382,785.91	408,010.00	(25,224.09)	-6.2%
5.5	SALES COMMDTY	$	203,152.78	203,126.44	26.34	0.0%	3,385,875.51	3,385,436.57	438.94	0.0%
5.6	TOTAL SALES	$	244,555.09	244,242.98	312.11	0.1%	3,967,978.81	3,973,284.38	(5,305.57)	-0.1%
5.7	TOTAL T-SERVICE	$	41,402.31	41,116.54	285.77	0.7%	582,103.30	587,847.81	(5,744.51)	-1.0%
5.8	SALES UNIT RATE	$/m³	0.4086	0.4080	0.0005	0.1%	0.3977	0.3983	(0.0005)	-0.1%
5.9	T-SERVICE UNIT RATE	$/m³	0.0692	0.0687	0.0005	0.7%	0.0583	0.0589	(0.0006)	-1.0%
5.10	SALES UNIT RATE	$/GJ	10.840	10.826	0.0138	0.1%	10.553	10.567	(0.0141)	-0.1%
5.11	T-SERVICE UNIT RATE	$/GJ	1.835	1.823	0.0127	0.7%	1.548	1.563	(0.0153)	-1.0%

			Rate 110 - Average Ind. Firm - 75% LF				Rate 115 - Large Ind. Firm - 80% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
6.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
6.2	CUSTOMER CHG.	$	6,654.00	6,000.00	654.00	10.9%	7,329.36	6,000.00	1,329.36	22.2%
6.3	DISTRIBUTION CHG.	$	147,234.78	132,976.24	14,258.54	10.7%	833,250.76	680,131.14	153,119.62	22.5%
6.4	LOAD BALANCING	$	382,785.88	408,009.99	(25,224.11)	-6.2%	2,121,650.86	2,243,819.74	(122,168.88)	-5.4%
6.5	SALES COMMDTY	$	3,385,875.17	3,385,436.23	438.94	0.0%	23,701,129.63	23,698,056.97	3,072.66	0.0%
6.6	TOTAL SALES	$	3,922,549.83	3,932,422.46	(9,872.63)	-0.3%	26,663,360.61	26,628,007.85	35,352.76	0.1%
6.7	TOTAL T-SERVICE	$	536,674.66	546,986.23	(10,311.57)	-1.9%	2,962,230.98	2,929,950.88	32,280.10	1.1%
6.8	SALES UNIT RATE	$/m³	0.3932	0.3942	(0.0010)	-0.3%	0.3818	0.3813	0.0005	0.1%
6.9	T-SERVICE UNIT RATE	$/m³	0.0538	0.0548	(0.0010)	-1.9%	0.0424	0.0420	0.0005	1.1%
6.10	SALES UNIT RATE	$/GJ	10.432	10.459	(0.0263)	-0.3%	10.130	10.117	0.0134	0.1%
6.11	T-SERVICE UNIT RATE	$/GJ	1.427	1.455	(0.0274)	-1.9%	1.125	1.113	0.0123	1.1%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 135 - Seasonal Firm				Rate 170 - Average Ind. Interr. - 50% LF			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
7.1	VOLUME	m³	598,567	598,567	0	0.0%	9,976,121	9,976,121	0	0.0%
7.2	CUSTOMER CHG.	$	1,326.36	1,200.00	126.36	10.5%	3,227.40	2,400.00	827.40	34.5%
7.3	DISTRIBUTION CHG.	$	7,702.7	6,860.83	841.86	12.3%	75,680.3	58,174.28	17,505.98	30.1%
7.4	LOAD BALANCING	$	10,371.32	11,019.54	(648.23)	-5.9%	221,011.85	235,142.50	(14,130.65)	-6.0%
7.5	SALES COMMDTY	$	203,526.55	204,204.13	(677.58)	-0.3%	3,385,875.51	3,385,436.57	438.94	0.0%
7.6	TOTAL SALES	$	222,926.92	223,284.50	(357.59)	-0.2%	3,685,795.02	3,681,153.35	4,641.67	0.1%
7.7	TOTAL T-SERVICE	$	19,400.37	19,080.37	319.99	1.7%	299,919.51	295,716.78	4,202.73	1.4%
7.8	SALES UNIT RATE	$/m³	0.3724	0.3730	(0.0006)	-0.2%	0.3695	0.3690	0.0005	0.1%
7.9	T-SERVICE UNIT RATE	$/m³	0.0324	0.0319	0.0005	1.7%	0.0301	0.0296	0.0004	1.4%
7.10	SALES UNIT RATE	$/GJ	9.882	9.897	(0.0159)	-0.2%	9.803	9.790	0.0123	0.1%
7.11	T-SERVICE UNIT RATE	$/GJ	0.860	0.846	0.0142	1.7%	0.798	0.786	0.0112	1.4%

			Rate 170 - Average Ind. Interr. - 75% LF				Rate 170 - Large Ind. Interr. - 75% LF			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
8.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
8.2	CUSTOMER CHG.	$	3,227.40	2,400.00	827.40	34.5%	3,227.40	2,400.00	827.40	34.5%
8.3	DISTRIBUTION CHG.	$	68,621.1	53,272.96	15,348.09	28.8%	364,777.9	257,316.22	107,461.68	41.8%
8.4	LOAD BALANCING	$	221,011.84	235,142.45	(14,130.61)	-6.0%	1,547,083.01	1,645,997.54	(98,914.53)	-6.0%
8.5	SALES COMMDTY	$	3,385,875.17	3,385,436.23	438.94	0.0%	23,701,129.63	23,698,056.97	3,072.66	0.0%
8.6	TOTAL SALES	$	3,678,735.46	3,676,251.64	2,483.82	0.1%	25,616,217.94	25,603,770.73	12,447.21	0.0%
8.7	TOTAL T-SERVICE	$	292,860.29	290,815.41	2,044.88	0.7%	1,915,088.31	1,905,713.76	9,374.55	0.5%
8.8	SALES UNIT RATE	$/m³	0.3688	0.3685	0.0002	0.1%	0.3668	0.3666	0.0002	0.0%
8.9	T-SERVICE UNIT RATE	$/m³	0.0294	0.0292	0.0002	0.7%	0.0274	0.0273	0.0001	0.5%
8.10	SALES UNIT RATE	$/GJ	9.784	9.777	0.0066	0.1%	9.733	9.728	0.0047	0.0%
8.11	T-SERVICE UNIT RATE	$/GJ	0.779	0.773	0.0054	0.7%	0.728	0.724	0.0036	0.5%

Revenue Adjustment Rider (Rider E) Summary
Period: April 1st to December 31st, 2007

	Col. 1	Col. 2	Col. 3
Item No.	**Description**	**Sales Service** (cent/m^3)	**Transportation Service** (cent/m^3)
1.	**Rate 1**	0.2688	0.2310
2.	**Rate 6**	0.0798	0.0185
3.	**Rate 9**	0.2598	0.2586
4.	**Rate 100**	(0.1788)	(0.1732)
5.	**Rate 110**	(0.0327)	(0.0346)
6.	**Rate 115**	0.0132	0.0117
7.	**Rate 125**	-	-
7.	**Rate 135**	0.0038	0.0038
8.	**Rate 145**	(0.1556)	(0.1402)
9.	**Rate 170**	0.0174	0.0153
10.	**Rate 200**	0.1244	0.1204
11.	**Rate 300**	n/a	(0.0640)

Notes: Sales Service Rider includes Distribution, Gas Supply Load Balancing and Gas Supply Commodity unit rates shown on Page 2.
Transportation Service Rider equals Sales Service Rider less Gas Supply Commodity unit rate.

Derivation of Revenue Adjustment Rider (Rider E) Unit Rates
Period: April 1st to December 31st, 2007

Schedule 1

Col. 1		Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
Item No.	**Description**	**Distribution Def/ (Suff) ($000) Jan-Mar 2007**	**Delivery Volumes (1000 m^3) Apr-Dec 2007**	**Unit Rate (¢/m^3)**	**Gas Supply Load Balancing Def/ (Suff) ($000) Jan-Mar 2007**	**Delivery Volumes (1000 m^3) Apr-Dec 2007**	**Unit Rate (¢/m^3)**	**Gas Supply Commodity Def/ (Suff) ($000) Jan-Mar 2007**	**Sales Volumes (1000 m^3) Apr-Dec 2007**	**Unit Rate (¢/m^3)**
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
1.	**Rate 1**	13,545	2,276,857	0.5949	(8,286)	2,276,857	(0.3639)	530	1,401,686	0.0378
2.	**Rate 6**	6,719	1,588,789	0.4229	(6,425)	1,588,789	(0.4044)	437	712,993	0.0613
3.	**Rate 9**	17	5,720	0.2974	(2)	5,720	(0.0388)	0	4,205	0.0013
4.	**Rate 100**	1,386	771,680	0.1796	(2,723)	771,680	(0.3528)	(7)	120,960	(0.0056)
5.	**Rate 110**	330	430,902	0.0766	(479)	430,902	(0.1112)	1	34,894	0.0019
6.	**Rate 115**	490	670,886	0.0730	(412)	670,886	(0.0614)	0	30,931	0.0015
7.	**Rate 125**	-	-	0.0000	-	-	0.0000	n/a	n/a	0.0000
8.	**Rate 135**	2	54,721	0.0038	(0)	54,721	0.0000	(0)	5,208	(0.0000)
9.	**Rate 145**	12	150,723	0.0080	(223)	150,723	(0.1482)	(4)	25,176	(0.0154)
10.	**Rate 170**	404	497,952	0.0812	(328)	497,952	(0.0659)	1	38,786	0.0021
11.	**Rate 200**	285	83,245	0.3428	(185)	83,245	(0.2224)	3	61,849	0.0041
12.	**Rate 300**	(15)	23,455	(0.0640)	n/a	n/a		n/a	n/a	
13.	**CDS**	-	-			-				
14.	**Total**	23,176	6,554,930		(19,063)	6,531,475		961	2,436,688	

EB-2006-0034 SALES AND TOTAL VOLUME SUMMARY

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 9	Col. 10	Col. 11	Col. 12	Col. 12
		JAN	FEB	MAR	APR	Schedule 1	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	TOTAL SALES VOLUME (10^3 m^3) - by Rate													
1.01	Rate 1	498,396	459,047	397,875	283,590	156,555	84,666	74,786	67,198	59,540	92,638	226,845	355,868	2,757,004
1.02	Rate 6	255,899	259,702	214,874	160,187	85,399	41,275	33,477	27,416	29,984	38,683	114,939	181,633	1,443,468
1.03	Rate 9	390	401	412	423	434	445	456	467	478	489	500	511	5,409
1.04	TOTAL GS SALES	754,686	719,150	613,162	444,200	242,388	126,386	108,719	95,081	90,002	131,810	342,284	538,012	4,205,881
1.05	Rate 100	35,277	32,346	29,765	21,958	14,334	7,528	6,125	6,117	7,797	10,993	18,995	27,113	218,347
1.06	Rate 110	5,100	4,984	5,059	4,338	4,058	3,540	3,283	3,355	3,679	3,886	4,155	4,602	50,038
1.07	Rate 115	3,500	3,561	3,670	3,611	3,614	3,589	2,438	3,514	3,487	3,615	3,646	3,416	41,661
1.08	Rate 135	0	0	0	37	493	626	745	894	795	762	722	134	5,208
1.09	Rate 145	6,345	4,601	5,020	3,303	2,480	1,763	1,630	1,731	1,832	2,710	4,106	5,621	41,142
1.10	Rate 170	6,292	6,086	6,260	5,329	4,245	3,497	3,683	3,694	3,302	3,634	4,970	6,431	57,424
1.11	Rate 180	-	-	-	-	-	-	-	-	-	-	-	-	-
1.12	Rate 200	20,950	19,792	16,358	11,774	6,563	3,995	3,292	3,071	3,151	5,649	9,814	14,541	118,949
1.13	TOTAL LV Sales Vol	77,464	71,370	66,132	50,350	35,786	24,538	21,197	22,376	24,043	31,249	46,409	61,858	532,770
1.14	TOTAL Sales	832,150	790,519	679,294	494,551	278,174	150,924	129,916	117,457	114,045	163,058	388,693	599,870	4,738,651
1	CUMULATIVE	832,150	1,622,669	2,301,963	2,796,513	3,074,687	3,225,611	3,355,527	3,472,984	3,587,029	3,750,088	4,138,781	4,738,651	
	TOTAL VOLUME SUMMARIES (10^3 m^3) - by Rate													
2.01	Total Rate 1	808,553	744,589	646,301	459,445	254,693	137,048	121,471	110,290	96,859	150,690	364,418	581,943	4,476,300
2.02	Total Rate 6	559,560	533,402	460,346	342,637	186,426	83,058	75,841	66,127	62,244	100,088	262,314	410,055	3,142,097
2.03	Total Rate 9	538	552	566	580	594	608	622	636	649	663	677	691	7,375
2.04	TOTAL GS VOL.	1,368,651	1,278,543	1,107,212	802,661	441,713	220,714	197,933	177,052	159,752	251,442	627,409	992,689	7,625,772
2.05	Total Rate 100	222,495	200,033	192,814	139,754	94,554	48,662	40,011	39,053	44,759	71,622	120,871	172,396	1,387,023
2.06	Total Rate 110	61,303	63,200	65,025	52,877	48,960	44,719	37,213	40,309	44,073	49,273	53,969	59,508	620,429
2.07	Total Rate 115	80,830	74,307	80,172	76,269	76,023	67,758	69,310	73,419	73,612	78,147	77,275	79,072	906,196
2.08	Total Rate 125 CD	-	-	-	-	-	-	-	-	-	-	-	-	-
2.09	Total Rate 135	258	148	269	1,040	4,785	6,284	6,985	8,164	8,005	8,043	7,737	3,677	55,396
2.10	Total Rate 145	36,529	31,911	32,053	24,156	16,868	11,187	9,715	10,180	10,582	15,789	22,491	29,757	251,217
2.11	Total Rate 170	79,892	76,539	75,242	62,642	53,966	46,493	45,928	45,903	46,918	56,617	65,427	74,059	729,625
2.12	Total Rate 180	-	-	-	-	-	-	-	-	-	-	-	-	-
2.13	Total Rate 200	24,591	23,249	19,574	14,887	9,280	6,539	5,223	4,896	5,082	7,940	12,208	17,191	150,658
2.14	Total Rate 300	1,900	2,891	2,992	2,891	2,696	2,789	2,400	2,400	2,794	2,987	2,000	2,498	31,237
2.15	Total CDS	-	-	-	-	-	-	-	-	-	-	-	-	-
2.16	TOTAL LV VOL.	507,799	472,278	468,139	374,515	307,132	234,430	216,785	224,323	235,825	290,418	361,979	438,157	4,131,781
2.17	TOTAL VOLUME	1,876,450	1,750,821	1,575,352	1,177,177	748,845	455,144	414,718	401,376	395,577	541,860	989,387	1,430,847	11,757,552
2	CUMULATIVE	1,876,450	3,627,271	5,202,623	6,379,799	7,128,644	7,583,788	7,998,506	8,399,881	8,795,458	9,337,318	10,326,706	11,757,552	

Total Revenue Variance From EB-2006-0034 to EB-2006-0099

Item No.	Col. 1	Col. 2 JAN	Col. 3 FEB	Col. 4 MAR	Col. 5 APR	Col. 6 MAY Schedule 1	Col. 7 JUN	Col. 8 JUL	Col. 9 AUG	Col. 9 SEP	Col. 10 OCT	Col. 11 NOV	Col. 12 DEC	Col. 12 TOTAL
	EB-2006-0034 Rates (Interim Rates)													
	TOTAL REVENUE SUMMARIES ($' 000) - by Rate													
1.01	Total Rate 1	299,402	277,533	243,628	179,762	108,935	68,177	62,644	58,523	54,063	72,944	147,909	220,990	1,794,509
1.02	Total Rate 6	149,253	148,152	125,724	95,180	53,561	27,132	23,438	20,313	20,783	28,025	71,501	109,037	872,099
1.03	Total Rate 9	211	217	223	228	234	239	245	251	256	262	267	273	2,907
1.04	TOTAL GS REV.	448,866	425,903	369,575	275,170	162,729	95,548	86,327	79,087	75,102	101,231	219,677	330,300	2,669,514.8
1.05	Total Rate 100	30,122	27,499	26,100	19,594	13,660	7,820	6,659	6,563	7,573	10,759	17,196	23,719	197,263.7
1.06	Total Rate 110	5,193	5,235	5,338	4,573	4,308	3,948	3,542	3,697	3,968	4,261	4,553	4,945	53,561
1.07	Total Rate 115	4,548	4,358	4,584	4,439	4,433	4,159	3,818	4,315	4,312	4,502	4,484	4,464	52,415
1.08	Total Rate 125	-	-	-	-	259	259	259	259	259	-	-	-	1,296
1.09	Total Rate 135	(92)	(100)	(90)	(59)	351	451	517	611	571	561	536	339	3,596
1.10	Total Rate 145	4,016	3,192	3,341	2,362	1,950	1,410	1,286	1,343	1,400	1,972	2,788	3,668	28,727
1.11	Total Rate 170	3,194	2,999	3,009	2,217	3,718	3,180	3,223	3,228	3,132	3,616	4,404	5,225	41,145
1.12	Total Rate 180	-	-	-	-	-	-	-	-	-	-	-	-	-
1.13	Total Rate 200	8,409	8,068	6,709	4,907	2,843	1,827	1,519	1,427	1,464	2,462	4,101	5,967	49,704
1.14	Total Rate 300	7	10	11	10	9	10	8	8	10	10	7	9	110
1.15	Total CDS	-	-	-	-	-	-	-	-	-	-	-	-	-
1.16	TOTAL LV REV.	55,396	51,260	49,002	38,042	31,532	23,065	20,832	21,452	22,689	28,143	38,069	48,336	427,817
1.17	TOTAL REVENUE	504,263	477,163	418,577	313,212	194,261	118,613	107,158	100,538	97,791	129,374	257,746	378,635	3,097,332
1	CUMULATIVE	504,263	981,426	1,400,003	1,713,215	1,907,476	2,026,088	2,133,247	2,233,785	2,331,577	2,460,950	2,718,696	3,097,332	

Item No.	Col. 1	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	EB-2006-0099 Rates (July QRAM Rates)													
	TOTAL REVENUE SUMMARIES ($'000) - by Rate													
2.01	Total Rate 1	297,395	275,591	241,787	178,119	107,520	66,916	61,405	57,298	52,855	71,657	146,357	219,221	1,776,121
2.02	Total Rate 6	149,041	147,908	125,450	94,874	53,236	26,840	23,167	20,046	20,514	27,739	71,186	108,775	868,777
2.03	Total Rate 9	207	212	218	223	229	234	239	245	251	256	262	267	2,842
2.04	TOTAL GS REV.	446,643	423,711	367,455	273,216	160,985	93,991	84,811	77,589	73,619	99,653	217,805	328,263	2,647,739.8
2.05	Total Rate 100	30,694	27,911	26,460	19,575	13,319	7,152	5,930	5,827	6,877	10,254	17,043	23,933	194,975.9
2.06	Total Rate 110	5,239	5,284	5,392	4,601	4,328	3,960	3,538	3,700	3,978	4,282	4,584	4,987	53,872
2.07	Total Rate 115	4,525	4,326	4,560	4,410	4,403	4,117	3,779	4,281	4,279	4,475	4,456	4,438	52,050
2.08	Total Rate 125	-	-	-	-	244	244	244	244	244	-	-	-	1,220
2.09	Total Rate 135	(93)	(101)	(91)	(60)	350	450	515	609	569	559	534	338	3,579
2.10	Total Rate 145	4,110	3,252	3,402	2,366	1,902	1,321	1,187	1,247	1,307	1,916	2,780	3,713	28,502
2.11	Total Rate 170	3,169	2,973	2,983	2,186	3,685	3,145	3,187	3,192	3,096	3,583	4,374	5,198	40,770
2.12	Total Rate 180	-	-	-	-	-	-	-	-	-	-	-	-	-
2.13	Total Rate 200	8,374	8,034	6,675	4,872	2,808	1,792	1,484	1,392	1,429	2,428	4,066	5,933	49,288
2.14	Total Rate 300	7	10	26	25	19	10	8	8	10	10	7	9	150
2.15	Total CDS	-	-	-	-	-	-	-	-	-	-	-	-	-
2.16	TOTAL LV REV.	56,025	51,689	49,407	37,976	31,059	22,191	19,871	20,500	21,789	27,507	37,844	48,548	424,407
2.17	TOTAL REVENUE	502,667	475,401	416,861	311,192	192,044	116,182	104,683	98,089	95,408	127,160	255,649	376,811	3,072,146
2	CUMULATIVE	502,667	978,068	1,394,929	1,706,122	1,898,165	2,014,347	2,119,030	2,217,119	2,312,527	2,439,687	2,695,336	3,072,146	

Item No.	Col. 1	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	VARIANCE- TOTAL REVENUE ($'000) - by Rate													
3.01	Total Rate 1	2,006	1,942	1,841	1,644	1,415	1,260	1,239	1,225	1,208	1,287	1,552	1,769	18,388
3.02	Total Rate 6	213	244	274	306	324	291	271	267	270	285	315	262	3,322
3.03	Total Rate 9	5	5	5	5	5	5	5	6	6	6	6	6	65
3.04	TOTAL GS REV.	2,224	2,191	2,120	1,954	1,744	1,557	1,515	1,498	1,483	1,578	1,872	2,037	21,775.0
3.05	Total Rate 100	(572)	(412)	(360)	18	341	668	730	736	696	504	153	(214)	2,287.9
3.06	Total Rate 110	(46)	(49)	(53)	(28)	(20)	(12)	4	(3)	(10)	(21)	(31)	(42)	(311)
3.07	Total Rate 115	23	32	24	29	30	41	39	33	33	27	28	26	365
3.08	Total Rate 125	-	-	-	-	15	15	15	15	15	-	-	-	76
3.09	Total Rate 135	1	1	1	1	1	2	2	2	2	2	2	1	17
3.10	Total Rate 145	(94)	(60)	(61)	(4)	48	89	100	96	93	56	7	(45)	225
3.11	Total Rate 170	25	26	26	30	33	36	36	36	36	33	30	27	375
3.12	Total Rate 180	-	-	-	-	-	-	-	-	-	-	-	-	-
3.13	Total Rate 200	34	34	34	35	35	35	35	35	35	35	35	34	416
3.14	Total Rate 300	-	-	(15)	(15)	(10)	-	-	-	-	-	-	-	(40)
3.15	Total CDS	-	-	-	-	-	-	-	-	-	-	-	-	-
3.16	TOTAL LV REV.	(629)	(429)	(404)	66	473	874	960	952	900	636	225	(213)	3,410
3.17	TOTAL REVENUE	1,595	1,762	1,716	2,020	2,217	2,431	2,476	2,450	2,383	2,214	2,097	1,825	25,185
3	CUMULATIVE	1,595	3,358	5,073	7,093	9,310	11,741	14,217	16,667	19,050	21,263	23,360	25,185	

Total Distribution Revenue Variance From EB-2006-0034 to EB-2006-0099

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 9	Col. 10	Col. 11	Col. 12	Col. 12
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	EB-2006-0034 Rates (Interim Rates)					Schedule 1								
	TOTAL DISTRIBUTION REVENUE SUMMARIES ($'000) - by Rate													
1.01	**Total Rate 1**	92,355	86,839	78,303	61,980	43,865	33,019	31,569	30,549	29,316	34,441	53,836	72,942	649,015
1.02	**Total Rate 6**	35,541	34,352	30,683	24,353	15,627	9,125	8,439	7,843	7,614	10,115	19,916	27,726	231,335
1.03	**Total Rate 9**	59	61	62	63	65	66	67	69	70	72	73	74	802
1.04	**TOTAL GS REV.**	127,955	121,252	109,048	86,397	59,557	42,210	40,076	38,461	37,000	44,628	73,825	100,742	881,151.3
1.05	**Total Rate 100**	8,499	7,844	7,635	6,080	4,694	3,155	2,845	2,794	2,985	3,922	5,506	7,040	62,998.3
1.06	**Total Rate 110**	1,110	1,118	1,126	1,072	1,052	1,031	1,000	1,012	1,028	1,051	1,072	1,100	12,772
1.07	**Total Rate 115**	904	892	903	896	897	882	884	892	892	901	899	902	10,744
1.08	**Total Rate 125**	-	-	-	-	259	259	259	259	259	-	-	-	1,296
1.09	**Total Rate 135**	18	13	19	18	61	76	84	96	94	95	92	199	865
1.10	**Total Rate 145**	604	561	561	489	419	354	336	339	345	406	474	542	5,430
1.11	**Total Rate 170**	524	514	510	464	431	403	402	404	406	446	479	509	5,492
1.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
1.13	**Total Rate 200**	364	351	316	270	216	190	177	174	176	204	245	293	2,976
1.14	**Total Rate 300**	7	10	11	10	9	10	8	8	10	10	7	9	110
1.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
1.16	**TOTAL LV REV.**	12,029	11,303	11,082	9,299	8,039	6,360	5,995	5,978	6,197	7,034	8,774	10,593	102,683
1.17	**TOTAL REVENUE**	139,984	132,555	120,130	95,696	67,595	48,570	46,071	44,439	43,197	51,662	82,599	111,335	983,834
1	**CUMULATIVE**	139,984	272,540	392,669	488,365	555,961	604,531	650,602	695,041	738,238	789,900	872,499	983,834	
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	EB-2006-0099 Rates (July QRAM Rates)													
	TOTAL DISTRIBUTION REVENUE SUMMARIES ($'000) - by Rate													
2.01	**Total Rate 1**	87,498	82,271	74,183	58,717	41,552	31,275	29,901	28,935	27,767	32,623	51,000	69,119	614,841
2.02	**Total Rate 6**	33,167	32,057	28,633	22,726	14,583	8,515	7,875	7,319	7,105	9,439	18,585	25,877	215,880
2.03	**Total Rate 9**	54	55	56	57	59	60	61	62	64	65	66	67	727
2.04	**TOTAL GS REV.**	120,718	114,384	102,872	81,501	56,194	39,850	37,838	36,316	34,935	42,127	69,651	95,064	831,448.1
2.05	**Total Rate 100**	8,084	7,369	7,140	5,442	3,934	2,271	1,938	1,884	2,091	3,100	4,817	6,490	54,558.4
2.06	**Total Rate 110**	1,001	1,008	1,015	966	949	930	902	912	927	948	966	992	11,516
2.07	**Total Rate 115**	740	730	739	734	734	722	724	730	730	737	736	738	8,795
2.08	**Total Rate 125**	-	-	-	-	244	244	244	244	244	-	-	-	1,220
2.09	**Total Rate 135**	17	12	19	16	54	67	74	84	83	83	80	193	782
2.10	**Total Rate 145**	615	549	550	438	333	240	214	220	228	315	416	520	4,637
2.11	**Total Rate 170**	386	380	377	345	322	302	301	303	304	333	357	377	4,086
2.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
2.13	**Total Rate 200**	263	254	228	196	157	137	128	126	127	147	177	212	2,152
2.14	**Total Rate 300**	7	10	26	25	19	10	8	8	10	10	7	9	150
2.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
2.16	**TOTAL LV REV.**	11,112	10,312	10,095	8,162	6,745	4,923	4,533	4,512	4,744	5,673	7,556	9,530	87,897
2.17	**TOTAL REVENUE**	131,830	124,696	112,967	89,663	62,938	44,773	42,370	40,828	39,679	47,800	77,207	104,593	919,345
2	**CUMULATIVE**	131,830	256,526	369,493	459,156	522,094	566,867	609,237	650,065	689,745	737,544	814,751	919,345	
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	VARIANCE- TOTAL DISTRIBUTION REVENUE ($'000) - by Rate													
3.01	**Total Rate 1**	4,857	4,568	4,120	3,263	2,313	1,744	1,668	1,614	1,549	1,818	2,836	3,822	34,174
3.02	**Total Rate 6**	2,374	2,295	2,050	1,627	1,044	610	564	525	509	676	1,331	1,849	15,455
3.03	**Total Rate 9**	6	6	6	6	6	6	6	6	7	7	7	7	75
3.04	**TOTAL GS REV.**	7,237	6,868	6,176	4,896	3,363	2,360	2,238	2,145	2,065	2,501	4,174	5,679	49,704.2
3.05	**Total Rate 100**	415	476	495	638	760	884	907	910	894	822	689	550	8,440
3.06	**Total Rate 110**	109	110	111	105	103	101	98	99	101	103	106	108	1,255
3.07	**Total Rate 115**	164	162	164	163	163	160	160	162	162	163	163	164	1,948
3.08	**Total Rate 125**	-	-	-	-	15	15	15	15	15	-	-	-	76
3.09	**Total Rate 135**	1	1	1	2	7	9	10	12	12	12	11	6	82
3.10	**Total Rate 145**	(11)	12	11	50	86	114	122	119	117	92	58	23	793
3.11	**Total Rate 170**	138	134	133	119	109	101	101	101	102	113	122	132	1,406
3.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
3.13	**Total Rate 200**	101	97	87	75	60	53	49	48	49	56	68	81	824
3.14	**Total Rate 300**	-	-	(15)	(15)	(10)	-	-	-	-	-	-	-	(40)
3.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
3.16	**TOTAL LV REV.**	917	991	987	1,137	1,294	1,437	1,462	1,466	1,452	1,361	1,218	1,063	14,786
3.17	**TOTAL REVENUE**	8,154	7,860	7,163	6,033	4,657	3,797	3,701	3,611	3,517	3,863	5,392	6,742	64,490
3	**CUMULATIVE**	8,154	16,014	23,176	29,209	33,867	37,664	41,364	44,976	48,493	52,356	57,747	64,489	

Total Load Balancing Revenue Variance From EB-2006-0034 to EB-2006-0099

Schedule 1

EB-2006-0034 Rates (Interim Rates)

TOTAL LOAD BALANCING REVENUE SUMMARIES ($'000) - by Rate

Item No.	Col. 1	Col. 2 JAN	Col. 3 FEB	Col. 4 MAR	Col. 5 APR	Col. 6 MAY	Col. 7 JUN	Col. 8 JUL	Col. 9 AUG	Col. 9 SEP	Col. 10 OCT	Col. 11 NOV	Col. 12 DEC	Col. 12 TOTAL
1.01	Total Rate 1	37,050	34,119	29,615	21,053	11,671	6,280	5,566	5,054	4,438	6,905	16,698	26,666	205,114
1.02	Total Rate 6	26,011	24,795	21,399	15,928	8,666	3,861	3,525	3,074	2,893	4,653	12,194	19,062	146,062
1.03	Total Rate 9	20	20	21	21	22	22	23	23	24	24	25	25	270
1.04	TOTAL GS REV.	63,081	58,934	51,035	37,002	20,358	10,163	9,114	8,151	7,355	11,582	28,917	45,753	351,444.9
1.05	Total Rate 100	9,631	8,658	8,346	6,049	4,093	2,106	1,732	1,690	1,937	3,100	5,232	7,462	60,037.6
1.06	Total Rate 110	2,352	2,425	2,495	2,029	1,879	1,716	1,428	1,547	1,691	1,891	2,071	2,283	23,806
1.07	Total Rate 115	2,456	2,258	2,436	2,317	2,310	2,059	2,106	2,231	2,236	2,374	2,348	2,402	27,532
1.08	Total Rate 125	-	-	-	-	-	-	-	-	-	-	-	-	-
1.09	Total Rate 135	(110)	(113)	(110)	(90)	123	162	180	210	206	207	199	95	960
1.10	Total Rate 145	1,253	1,065	1,071	749	687	456	396	415	431	643	916	1,212	9,293
1.11	Total Rate 170	534	419	375	(56)	1,846	1,590	1,571	1,570	1,605	1,937	2,238	2,533	16,164
1.12	Total Rate 180	-	-	-	-	-	-	-	-	-	-	-	-	-
1.13	Total Rate 200	934	1,000	842	640	399	281	225	211	219	341	525	739	6,356
1.14	Total Rate 300	-	-	-	-	-	-	-	-	-	-	-	-	-
1.15	Total CDS	-	-	-	-	-	-	-	-	-	-	-	-	-
1.16	TOTAL LV REV.	17,050	15,712	15,454	11,639	11,337	8,370	7,637	7,873	8,326	10,494	13,529	16,728	144,149
1.17	TOTAL REVENUE	80,131	74,647	66,489	48,640	31,695	18,533	16,751	16,024	15,681	22,075	42,446	62,480	495,594
1	CUMULATIVE	80,131	154,777	221,267	269,907	301,602	320,135	336,886	352,911	368,592	390,667	433,114	495,594	

EB-2006-0099 Rates (July QRAM Rates)

TOTAL LOAD BALANCING REVENUE SUMMARIES ($'000) - by Rate

Item No.	Col. 1	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
2.01	Total Rate 1	40,096	36,924	32,050	22,784	12,630	6,796	6,024	5,469	4,803	7,473	18,071	28,858	221,977
2.02	Total Rate 6	28,326	27,002	23,303	17,345	9,437	4,205	3,839	3,347	3,151	5,067	13,279	20,758	159,058
2.03	Total Rate 9	20	21	21	22	22	23	24	24	25	25	26	26	279
2.04	TOTAL GS REV.	68,442	63,946	55,375	40,150	22,090	11,024	9,886	8,841	7,979	12,564	31,376	49,642	381,314.4
2.05	Total Rate 100	10,615	9,544	9,199	6,668	4,511	2,322	1,909	1,863	2,135	3,417	5,767	8,225	66,174.4
2.06	Total Rate 110	2,507	2,585	2,659	2,163	2,002	1,829	1,522	1,649	1,803	2,015	2,207	2,434	25,375
2.07	Total Rate 115	2,597	2,388	2,576	2,451	2,443	2,177	2,227	2,359	2,365	2,511	2,483	2,541	29,117
2.08	Total Rate 125	-	-	-	-	-	-	-	-	-	-	-	-	-
2.09	Total Rate 135	(110)	(113)	(110)	(89)	128	169	188	219	215	216	208	99	1,020
2.10	Total Rate 145	1,334	1,136	1,142	803	725	481	417	437	455	678	966	1,278	9,852
2.11	Total Rate 170	647	528	482	33	1,923	1,656	1,636	1,635	1,671	2,017	2,331	2,638	17,198
2.12	Total Rate 180	-	-	-	-	-	-	-	-	-	-	-	-	-
2.13	Total Rate 200	1,002	1,064	896	681	425	299	239	224	233	363	559	787	6,770
2.14	Total Rate 300	-	-	-	-	-	-	-	-	-	-	-	-	-
2.15	Total CDS	-	-	-	-	-	-	-	-	-	-	-	-	-
2.16	TOTAL LV REV.	18,593	17,130	16,844	12,708	12,156	8,932	8,138	8,387	8,877	11,218	14,520	18,001	155,506
2.17	TOTAL REVENUE	87,035	81,077	72,219	52,859	34,246	19,956	18,024	17,227	16,855	23,782	45,896	67,643	536,820
2	CUMULATIVE	87,035	168,112	240,330	293,189	327,435	347,392	365,416	382,643	399,498	423,281	469,177	536,820	

VARIANCE- TOTAL LOAD BALANCING REVENUE ($'000) - by Rate

Item No.	Col. 1	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
3.01	Total Rate 1	(3,046)	(2,805)	(2,435)	(1,731)	(959)	(516)	(458)	(415)	(365)	(568)	(1,373)	(2,192)	(16,865)
3.02	Total Rate 6	(2,314)	(2,206)	(1,904)	(1,417)	(771)	(344)	(314)	(274)	(257)	(414)	(1,085)	(1,696)	(12,996)
3.03	Total Rate 9	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(10)
3.04	TOTAL GS REV.	(5,361)	(5,012)	(4,340)	(3,149)	(1,731)	(861)	(772)	(690)	(623)	(983)	(2,459)	(3,889)	(29,871.5)
3.05	Total Rate 100	(984)	(885)	(853)	(618)	(418)	(215)	(177)	(173)	(198)	(317)	(535)	(763)	(6,136.8)
3.06	Total Rate 110	(155)	(160)	(164)	(134)	(124)	(113)	(94)	(102)	(111)	(125)	(136)	(150)	(1,569)
3.07	Total Rate 115	(141)	(130)	(140)	(133)	(133)	(119)	(121)	(128)	(129)	(137)	(135)	(138)	(1,585)
3.08	Total Rate 125	-	-	-	-	-	-	-	-	-	-	-	-	-
3.09	Total Rate 135	(0)	(0)	(0)	(1)	(5)	(7)	(8)	(9)	(9)	(9)	(8)	(4)	(60)
3.10	Total Rate 145	(81)	(71)	(71)	(54)	(38)	(25)	(22)	(23)	(24)	(35)	(50)	(66)	(559)
3.11	Total Rate 170	(113)	(108)	(107)	(89)	(76)	(66)	(65)	(65)	(66)	(80)	(93)	(105)	(1,033)
3.12	Total Rate 180	-	-	-	-	-	-	-	-	-	-	-	-	-
3.13	Total Rate 200	(68)	(64)	(54)	(41)	(25)	(18)	(14)	(13)	(14)	(22)	(34)	(47)	(414)
3.14	Total Rate 300	-	-	-	-	-	-	-	-	-	-	-	-	-
3.15	Total CDS	-	-	-	-	-	-	-	-	-	-	-	-	-
3.16	TOTAL LV REV.	(1,543)	(1,418)	(1,390)	(1,070)	(820)	(562)	(501)	(513)	(551)	(724)	(991)	(1,274)	(11,357)
3.17	TOTAL REVENUE	(6,904)	(6,430)	(5,729)	(4,219)	(2,551)	(1,423)	(1,273)	(1,203)	(1,174)	(1,707)	(3,450)	(5,163)	(41,228)
3	CUMULATIVE	(6,904)	(13,334)	(19,063)	(23,282)	(25,833)	(27,256)	(28,529)	(29,732)	(30,907)	(32,613)	(36,063)	(41,226)	

Total Commodity Revenue Variance From EB-2006-0034 to EB-2006-0099

Schedule 1

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 9	Col. 10	Col. 11	Col. 12	Col. 12
		JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
	EB-2006-0034 Rates (Interim Rates)													
	TOTAL COMMODITY REVENUE SUMMARIES ($'000) - by Rate													
1.01	**Total Rate 1**	169,997	156,575	135,710	96,729	53,399	28,878	25,509	22,920	20,308	31,598	77,374	121,382	940,381
1.02	**Total Rate 6**	87,701	89,004	73,641	54,899	29,268	14,146	11,473	9,396	10,276	13,257	39,392	62,249	494,702
1.03	**Total Rate 9**	132	136	140	144	147	151	155	159	162	166	170	174	1,836
1.04	**TOTAL GS REV.**	257,831	245,716	209,492	151,772	82,814	43,175	37,137	32,475	30,747	45,021	116,935	183,805	1,436,918.6
1.05	**Total Rate 100**	11,992	10,996	10,119	7,465	4,873	2,559	2,082	2,079	2,651	3,737	6,458	9,217	74,227.8
1.06	**Total Rate 110**	1,731	1,692	1,717	1,472	1,377	1,201	1,114	1,139	1,248	1,319	1,410	1,562	16,983
1.07	**Total Rate 115**	1,188	1,209	1,245	1,226	1,227	1,218	828	1,193	1,184	1,227	1,238	1,159	14,140
1.08	**Total Rate 125**	-	-	-	-	-	-	-	-	-	-	-	-	-
1.09	**Total Rate 135**	0	0	0	13	168	213	253	304	270	259	246	46	1,771
1.10	**Total Rate 145**	2,160	1,566	1,709	1,124	844	600	555	589	624	922	1,397	1,913	14,003
1.11	**Total Rate 170**	2,136	2,065	2,125	1,809	1,441	1,187	1,250	1,254	1,121	1,233	1,687	2,183	19,490
1.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
1.13	**Total Rate 200**	7,110	6,718	5,552	3,996	2,227	1,356	1,117	1,042	1,069	1,917	3,331	4,935	40,371
1.14	**Total Rate 300**	-	-	-	-	-	-	-	-	-	-	-	-	-
1.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
1.16	**TOTAL LV REV.**	26,317	24,245	22,466	17,104	12,156	8,334	7,200	7,600	8,167	10,615	15,766	21,015	180,985
1.17	**TOTAL REVENUE**	284,147	269,961	231,958	168,876	94,970	51,510	44,336	40,075	38,913	55,636	132,701	204,820	1,617,904
1	**CUMULATIVE**	284,147	554,108	786,066	954,942	1,049,913	1,101,422	1,145,759	1,185,833	1,224,747	1,280,383	1,413,084	1,617,904	

Item No.		**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
	EB-2006-0099 Rates (July QRAM Rates)													
	TOTAL COMMODITY REVENUE SUMMARIES ($'000) - by Rate													
2.01	**Total Rate 1**	169,802	156,396	135,555	96,618	53,338	28,845	25,479	22,894	20,285	31,561	77,285	121,243	939,303
2.02	**Total Rate 6**	87,548	88,849	73,513	54,803	29,217	14,121	11,453	9,380	10,258	13,234	39,323	62,140	493,839
2.03	**Total Rate 9**	132	136	140	144	147	151	155	159	162	166	170	174	1,835
2.04	**TOTAL GS REV.**	257,483	245,381	209,208	151,565	82,702	43,118	37,087	32,432	30,706	44,962	116,778	183,557	1,434,977.3
2.05	**Total Rate 100**	11,995	10,998	10,121	7,466	4,874	2,560	2,083	2,080	2,651	3,738	6,459	9,219	74,243.1
2.06	**Total Rate 110**	1,731	1,691	1,717	1,472	1,377	1,201	1,114	1,139	1,248	1,319	1,410	1,562	16,981
2.07	**Total Rate 115**	1,188	1,208	1,245	1,225	1,226	1,218	827	1,192	1,183	1,227	1,237	1,159	14,138
2.08	**Total Rate 125**	-	-	-	-	-	-	-	-	-	-	-	-	-
2.09	**Total Rate 135**	0	0	0	13	168	214	254	305	271	260	246	46	1,777
2.10	**Total Rate 145**	2,161	1,567	1,710	1,125	845	600	555	590	624	923	1,398	1,915	14,013
2.11	**Total Rate 170**	2,135	2,065	2,124	1,808	1,440	1,187	1,250	1,253	1,121	1,233	1,687	2,183	19,487
2.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
2.13	**Total Rate 200**	7,109	6,717	5,551	3,996	2,227	1,356	1,117	1,042	1,069	1,917	3,330	4,934	40,366
2.14	**Total Rate 300**	-	-	-	-	-	-	-	-	-	-	-	-	-
2.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
2.16	**TOTAL LV REV.**	26,319	24,247	22,468	17,105	12,158	8,335	7,201	7,601	8,168	10,616	15,768	21,017	181,005
2.17	**TOTAL REVENUE**	283,802	269,628	231,676	168,671	94,859	51,453	44,288	40,033	38,874	55,578	132,546	204,574	1,615,982
2	**CUMULATIVE**	283,802	553,430	785,106	953,776	1,048,636	1,100,089	1,144,377	1,184,410	1,223,284	1,278,862	1,411,408	1,615,982	

Item No.		**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
	VARIANCE- TOTAL COMMODITY REVENUE ($'000) - by Rate													
3.01	**Total Rate 1**	195	179	156	111	61	33	29	26	23	36	89	139	1,078
3.02	**Total Rate 6**	153	155	128	96	51	25	20	16	18	23	69	109	863
3.03	**Total Rate 9**	0	0	0	0	0	0	0	0	0	0	0	0	0
3.04	**TOTAL GS REV.**	348	335	284	207	112	58	49	43	41	59	157	248	1,941.3
3.05	**Total Rate 100**	(2)	(2)	(2)	(2)	(1)	(1)	(0)	(0)	(1)	(1)	(1)	(2)	(15.3)
3.06	**Total Rate 110**	0	0	0	0	0	0	0	0	0	0	0	0	2
3.07	**Total Rate 115**	0	0	0	0	0	0	0	0	0	0	0	0	2
3.08	**Total Rate 125**	-	-	-	-	-	-	-	-	-	-	-	-	-
3.09	**Total Rate 135**	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(6)
3.10	**Total Rate 145**	(2)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(10)
3.11	**Total Rate 170**	0	0	0	0	0	0	0	0	0	0	0	0	3
3.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
3.13	**Total Rate 200**	1	1	1	1	0	0	0	0	0	0	0	1	5
3.14	**Total Rate 300**	-	-	-	-	-	-	-	-	-	-	-	-	-
3.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
3.16	**TOTAL LV REV.**	(2)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(19)
3.17	**TOTAL REVENUE**	345	333	282	205	111	57	48	41	40	58	155	246	1,922
3	**CUMULATIVE**	345	678	961	1,166	1,277	1,334	1,382	1,423	1,463	1,521	1,676	1,922	

REVENUE TO COST/
RATE OF RETURN COMPARISONS
DEC. 31, 2007
(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col.10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300	Col. 14 RATE 300 CDS	Col. 15 RATE 305	Col. 16 RATE 325 & 330	Col. 17 DIRECT PURCHASE
1.	Sales and Trans. Revenue	3,100.67	1,794.58	872.14	2.91	197.26	53.56	52.42	1.30	3.60	28.73	41.15	49.70	0.00	0.00	0.12	1.66	1.56
2.	Unbilled Revenues	(2.10)	1.05	(3.56)	0.00	0.36	(0.01)	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	3,098.57	1,795.63	868.58	2.91	197.63	53.55	52.42	1.30	3.60	28.78	41.15	49.70	0.00	0.00	0.12	1.66	1.56
4.	Cost of Service	3,098.57	1,785.28	863.51	3.38	201.10	53.16	56.60	2.96	3.87	29.27	46.13	49.93	0.00	0.00	0.20	1.66	1.56
5.	Over/Under Contribution	(0.00)	10.35	5.06	(0.47)	(3.48)	0.38	(4.18)	(1.66)	(0.28)	(0.49)	(4.98)	(0.22)	0.00	0.00	(0.08)	(0.00)	(0.00)
6.	Over/Under Contribution ($ PER 10^3 m^3)	0.00	2.31	1.61	(64.13)	(2.51)	0.62	(4.62)	n/a	(5.01)	(1.93)	(6.83)	(1.47)	0.00	0.00	(2.45)	N/A	N/A
7.	Rate Base	3,743.60	2,313.16	874.80	5.19	230.03	41.29	24.57	9.66	1.78	21.86	22.38	12.27	0.00	0.00	0.67	185.95	N/A
8.	Return on Rate Base	6.08%	6.39%	6.49%	-0.40%	5.00%	6.74%	-6.01%	-6.14%	-5.01%	4.50%	-9.73%	4.79%	0.00%	0.00%	-1.99%	6.02%	N/A
9.	Revenue to Cost Ratio	1.00	1.01	1.01	0.86	0.98	1.01	0.93	0.44	0.93	0.98	0.89	1.00	0.00	0.00	0.61	1.00	1.00
10.	Revenue to Cost Ratio 2006 Board Decision	1.00	1.00	1.00	0.87	0.99	1.01	0.93	n/a	0.89	1.02	0.94	1.00	0.00	0.00	0.84	1.01	0.58

REVENUE TO COST/
RATE OF RETURN COMPARISONS
EXCLUDING GAS SUPPLY COMMODITY
DEC. 31, 2007

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col. 10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300	Col. 14 RATE 300 CDS	Col. 15 RATE 305	Col. 16 RATE 325 & 330	Col. 17 DIRECT PURCHASE
1.	Sales and Trans. Revenue	1,482.68	854.14	377.41	1.07	123.04	36.58	38.28	1.30	1.83	14.73	21.66	9.33	0.00	0.00	0.12	1.66	1.56
2.	Unbilled Revenues	(2.10)	1.05	(3.56)	0.00	0.36	(0.01)	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	1,480.58	855.20	373.85	1.07	123.40	36.57	38.28	1.30	1.83	14.78	21.66	9.33	0.00	0.00	0.12	1.66	1.56
4.	Cost of Service	1,480.58	844.84	368.78	1.54	126.87	36.18	42.46	2.96	2.10	15.27	26.64	9.55	0.00	0.00	0.20	1.66	1.56
5.	Over/Under Contribution	0.00	10.36	5.06	(0.47)	(3.48)	0.38	(4.18)	(1.66)	(0.28)	(0.49)	(4.98)	(0.22)	0.00	0.00	(0.08)	(0.00)	(0.00)
6.	Over/Under Contribution ($ PER 10^3 m^3)		2.31	1.61	(64.18)	(2.51)	0.62	(4.62)	n/a	(5.01)	(1.93)	(6.83)	(1.47)	0.00	0.00	0.00	N/A	N/A
7.	Rate Base	3,726.42	2,303.17	869.56	5.17	229.24	41.11	24.42	9.66	1.76	21.71	22.17	11.84	0.00	0.00	0.67	185.95	N/A
8.	Return on Rate Base	6.08%	6.39%	6.49%	-0.43%	5.00%	6.74%	-6.08%	-6.14%	-5.13%	4.49%	-9.88%	4.75%	0.00%	0.00%	-1.99%	6.02%	N/A
9.	Revenue to Cost Ratio	1.00	1.01	1.01	0.69	0.97	1.01	0.90	0.44	0.87	0.97	0.81	0.98	0.00	0.00	0.61	1.00	1.00
10.	Revenue to Cost Ratio 2006 Board Decision	1.00	1.01	1.01	0.69	0.98	1.01	0.90	n/a	0.87	1.03	0.89	0.98	0.00	0.00	0.84	1.01	0.58

Functionalization of
Ontario Utility Rate Base
Year Ended Dec. 31, 2007

(millions of dollars)

		Col. 1 Net Rate Base	Col. 2 Gas Supply	Col. 3 Storage	Col. 4 Sales Stations	Col. 5 Distribution Measurement	Col. 6 Services	Col. 7 Mains	Col. 8 Meters	Col. 9 Rental Equipment	Col. 10 Sales/ Marketing	Col. 11 Customer Accounting	Col. 12 Unidenti-fiable	Col. 13 Entrac	Col. 14 GST Revenue
1.	**Gas Supply**	2.37	0.00	2.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Distribution Plant														
2.1	Land (incl offers to buy)	8.32	0.08	0.00	0.04	0.02	0.99	0.80	0.02	0.00	1.34	3.55	1.49	0.00	0.00
2.2	Structures & Improvements	59.37	0.58	0.00	0.28	0.14	7.04	5.71	0.14	0.00	9.56	25.31	10.61	0.00	0.00
2.3	Mains	1,279.80	0.00	0.00	0.00	0.00	0.00	1,279.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.4	Meas. Reg. & Telemetering	158.40	0.00	0.00	84.28	74.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.5	Services	1,069.60	0.00	0.00	0.00	0.00	1,069.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Meters	229.10	0.00	0.00	0.00	0.00	0.00	0.00	229.10	0.00	0.00	0.00	0.00	0.00	0.00
2.	Total Distribution Plant	2,804.59	0.66	0.00	84.60	74.28	1,077.63	1,286.31	229.26	0.00	10.90	28.86	12.09	0.00	0.00
	General Plant														
3.1	Land (incl offers to buy)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2	Structures & Improvements	3.40	0.00	0.00	0.00	0.00	1.14	0.15	0.00	0.00	0.43	1.20	0.48	0.00	0.00
3.3	Office Furniture & Equip.	7.10	0.01	0.01	0.01	0.87	1.15	1.42	0.33	0.12	0.17	0.22	2.79	0.00	0.00
3.4	Transportation Equipment	18.50	0.00	0.00	0.00	0.04	5.49	12.37	0.00	0.00	0.60	0.00	0.00	0.00	0.00
3.5	Heavy Work Equipment	9.30	0.00	0.00	0.00	0.02	2.76	6.22	0.00	0.00	0.30	0.00	0.00	0.00	0.00
3.6	Tools & Work Equip.	15.30	0.00	0.00	0.00	0.00	7.65	7.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.7	Rental Equip.	7.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.70	0.00	0.00	0.00	0.00	0.00
3.8	Communication Equip.	3.20	0.04	0.00	0.03	0.91	0.28	0.40	0.00	0.00	0.30	0.55	0.70	0.00	0.00
3.9	Compressors	1.30	0.00	0.00	0.00	0.00	0.39	0.87	0.00	0.00	0.04	0.00	0.00	0.00	0.00
3.10	Computer Equipment	70.57	1.69	0.24	1.64	5.99	11.38	18.43	5.99	0.11	0.63	16.29	8.17	0.00	0.00
3.11	S.I.M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.12	Entrac	12.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.43	0.00
3.	Total General Plant	148.80	1.75	0.25	1.68	7.84	30.23	47.51	6.32	7.93	2.47	18.27	12.13	12.43	0.00
4.	**Other Plant**	0.10	0.00	0.00	0.00	0.00	0.04	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.	**Plant Held for Future Use**	1.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Other Items														
6.1	Working Capital Allowance	600.80	627.84	23.23	(0.90)	(0.99)	6.58	13.48	0.00	0.00	1.13	(55.33)	0.28	0.00	(14.53)
6.	Total Other Items	600.80	627.84	23.23	(0.90)	(0.99)	6.58	13.48	0.00	0.00	1.13	(55.33)	0.28	0.00	(14.53)
7.	**Total Rate Base**	3,557.65	630.25	25.85	85.38	81.13	1,115.47	1,347.35	235.58	7.93	14.51	(8.20)	24.50	12.43	(14.53)

Functionalization of
Ontario Utility Working Capital
Year Ended Dec. 31, 2007

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
		Total Requirement	Gas Supply	Storage	Sales Stations	Distribution Measurement	Services	Mains	Sales/ Marketing	Customer Accounting	Unidenti- fiable	GST Revenue
	Working Capital Allowance											
1.	Prepaid Expenses	2.70	0.00	0.00	0.00	0.00	0.33	0.33	0.02	0.00	2.01	0.00
	Materials & Supplies											
2.1	NGV Inventory	1.34	0.00	0.00	0.00	0.00	0.00	0.00	1.34	0.00	0.00	0.00
2.2	Pipe	3.09	0.00	0.00	0.00	0.00	0.70	2.39	0.00	0.00	0.00	0.00
2.3	Warehouse Inventory	5.07	0.00	0.00	0.00	0.00	2.53	2.53	0.00	0.00	0.00	0.00
2.4	Holding Account	9.14	0.00	0.00	0.00	0.00	4.57	4.57	0.00	0.00	0.00	0.00
3.	Mortgages Receivable	0.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.90	0.00
4.	Merchandise Sales Financed	0.10	0.00	0.00	0.00	0.00	0.00	0.00	2.60	0.00	(2.50)	0.00
5.	Rebilled Construction Work	6.90	0.00	0.00	0.00	0.00	0.00	6.90	0.00	0.00	0.00	0.00
6.	Gas in Inventory	613.10	613.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.	Customer Security Deposits	(42.80)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(42.80)	0.00	0.00
	Working Cash Allowance											
8.1	Gas Costs/O&M	(2.20)	20.67	1.37	(0.92)	(1.01)	(2.11)	(4.37)	(2.89)	(12.81)	(0.14)	0.00
8.2	GST	3.46	(5.93)	21.86	0.02	0.02	0.54	1.13	0.06	0.28	0.00	(14.53)
9.	**Total Working Capital**	600.80	627.84	23.23	(0.90)	(0.99)	6.58	13.48	1.13	(55.33)	0.28	(14.53)

Functionalization of
Ontario Utility Net Investments
Year Ended Dec. 31, 2007

(millions of dollars)

		Col. 1 Investment and Revenues	Col. 2 Gas Supply	Col. 3 Storage	Col. 4 Sales Stations	Col. 5 Distribution Measurement	Col. 6 Services	Col. 7 Mains	Col. 8 Meters	Col. 9 Rental Equipment	Col. 10 Sales/ Marketing	Col. 11 Customer Accounting	Col. 12 Unidenti-fiable	Col. 13 Entrac
	Investment Costs													
1.1	Depreciation	220.99	0.59	0.08	8.07	8.92	85.44	90.96	9.96	1.06	0.70	6.52	3.71	4.98
1.2	Municipal Taxes	34.82	0.02	0.00	0.16	0.15	10.95	21.80	0.01	0.00	0.37	0.97	0.41	0.00
1.3	Capital Taxes	9.80	0.01	0.00	0.04	0.04	3.08	6.13	0.00	0.00	0.10	0.27	0.11	0.00
1.	Total Investments	265.61	0.62	0.08	8.27	9.12	99.47	118.89	9.97	1.06	1.17	7.76	4.23	4.98
	Miscellaneous Revenues													
2.1	Rentals	(1.30)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(1.30)	0.00	0.00	0.00	0.00
2.2	Transactional Services	(3.63)	(3.74)	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.3	Miscellaneous Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.4	Late Payment Penalties	(8.00)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(8.00)	0.00	0.00
2.5	Sale and Rental of Property	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Customer Accounting Charge	(9.40)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(9.40)	0.00	0.00
2.7	Meter Charge	(0.20)	0.00	0.00	0.00	0.00	0.00	0.00	(0.20)	0.00	0.00	0.00	0.00	0.00
2.8	Service Alteration Charge	(0.84)	0.00	0.00	0.00	0.00	(0.84)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.	Total Revenues	(23.37)	(3.74)	0.11	0.00	0.00	(0.84)	0.00	(0.20)	(1.30)	0.00	(17.40)	0.00	0.00
3.	**Net Investments Total**	242.23	(3.12)	0.19	8.27	9.12	98.62	118.89	9.77	(0.24)	1.17	(9.64)	4.23	4.98

Functionalization of
Ontario Utility O&M
Year Ended Dec. 31, 2007
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(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
		Cost of Service	Fringe Benefits	Sub-Total	Supervision	Sub-Total	A&G Overhead	Total
	Gas Supply							
1.1	Gas Purchased	2,066.26	0.00	2,066.26	0.00	2,066.26	0.00	2,066.26
1.2	Gas Storage	131.10	0.33	131.43	0.00	131.43	0.00	131.43
1.3	A&G	0.00	0.00	0.00	0.00	0.00	12.78	12.78
1.4	System Gas Management	0.80	0.08	0.88	0.00	0.88	0.00	0.88
1.5	Direct Purchase Management	0.94	0.62	1.56	0.00	1.56	0.00	1.56
1.	Total Gas Supply	2,199.10	1.03	2,200.13	0.00	2,200.13	12.78	2,212.91
	Distribution Costs							
	Operating Costs							
2.1.1	Chart Processing	1.56	0.29	1.85	1.24	3.10	0.60	3.70
2.1.2	Distribution Sta.	1.02	0.17	1.19	0.80	1.99	0.39	2.37
2.1.3	Sub-total	2.58	0.46	3.04	2.04	5.08	0.99	6.07
2.1.4	Supervision M&R	0.79	0.22	1.01	(1.01)	0.00	0.00	0.00
2.1.5	System Operation	27.18	5.67	32.85	8.36	41.21	7.99	49.19
2.1.6	Sub-total	30.55	6.35	36.90	9.39	46.29	8.97	55.26
2.1.7	Supervision Dist Op	6.45	2.94	9.39	(9.39)	0.00	0.00	0.00
2.1.8	Gas Dispatched	4.16	0.66	4.82	0.00	4.82	0.93	5.75
2.1	Total Operating Costs	41.16	9.95	51.11	0.00	51.11	9.91	61.01
	Maintenance Costs							
2.2.1	Distribution Sys Reg	0.17	0.04	0.21	0.43	0.63	0.12	0.76
2.2.2	Sales Meters	0.47	0.12	0.59	1.22	1.81	0.35	2.16
2.2.3	Other Meters	2.37	0.70	3.07	6.42	9.49	1.84	11.33
2.2.4	Instruments	0.70	0.12	0.82	1.72	2.54	0.49	3.03
2.2.5	Sub-total M&R	3.71	0.98	4.69	9.79	14.47	2.81	17.28
2.2.6	Supervision M&R	3.18	1.13	4.31	(4.31)	0.00	0.00	0.00
2.2.7	Mains	6.65	1.99	8.64	5.27	13.90	2.70	16.60
2.2.8	Structures	0.13	0.00	0.13	0.08	0.21	0.04	0.25
2.2.9	Sub-total Mntce	13.67	4.09	17.76	10.83	28.59	5.54	34.13
2.2.10	Supervision Dist Mntce	8.30	2.53	10.83	(10.83)	0.00	0.00	0.00
2.2	Total Maintenance Costs	21.97	6.62	28.59	0.00	28.59	5.54	34.13
2.	Total Distribution Costs	63.13	16.57	79.70	0.00	79.70	15.45	95.15

Functionalization of
Ontario Utility O&M
Year Ended Dec. 31, 2007

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
		Cost of Service	Fringe Benefits	Sub-Total	Supervision	Sub-Total	A&G Overhead	Total
	Customer Service Costs							
	Operating Costs							
3.1.1	Heating Equipment Service	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.1.1	Other Service Work	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.1.2	Inspect Appl Inst.	1.64	0.30	1.94	0.38	2.32	0.45	2.77
3.1.3	Sub-total Service Work	1.64	0.30	1.94	0.38	2.32	0.45	2.77
3.1.4	Mtr Locks,Unlks,Exchanges	7.78	0.80	8.58	1.66	10.24	1.98	12.22
3.1.5	Jobbing Contracts Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.1.6	Sub-total	9.42	1.10	10.52	2.03	12.56	2.43	14.99
3.1.7	Training & Supervision	2.05	0.59	2.64	(2.64)	0.00	0.00	0.00
3.1	Total Operating Costs	11.47	1.69	13.16	(0.60)	12.56	2.43	14.99
	Maintenance Costs							
3.2.1	Co Equip on Cust. Premises	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2.2	Service Lines	2.27	0.85	3.12	0.60	3.73	0.72	4.45
3.2	Total Maintenance Costs	2.27	0.85	3.12	0.60	3.73	0.72	4.45
3.	Total Customer Service Costs	13.74	2.54	16.28	0.00	16.28	3.16	19.44
	Sales/Marketing Costs							
4.1	Residential Promotion	5.24	0.33	5.57	0.43	5.99	1.16	7.15
4.2	Commercial Promotion	1.89	0.73	2.62	0.20	2.82	0.55	3.37
4.3	Industrial Promotion	3.11	0.60	3.71	0.29	4.00	0.78	4.78
4.4	Res/Comm Promotions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.4	General Sales Promotion	3.29	0.86	4.15	0.32	4.47	0.87	5.33
4.5	Merchandising Expenses	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.6	NGV Operation	1.26	0.16	1.42	0.11	1.53	0.30	1.83
4.7	Contract Administration Costs	2.62	0.62	3.24	0.25	3.49	0.68	4.16
4.8	Sub-total	17.41	3.30	20.71	1.59	22.30	4.32	26.62
4.9	General Supervision	1.20	0.39	1.59	(1.59)	0.00	0.00	0.00
4.10	DSM - Program	16.99	0.00	16.99	0.00	16.99	3.29	20.28
4.11	DSM - General	5.01	1.83	6.84	0.00	6.84	1.33	8.16
4.	Total Sales	40.61	5.52	46.13	0.00	46.13	8.94	55.07

Functionalization of
Ontario Utility O&M
Year Ended Dec. 31, 2007

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
		Cost of Service	Fringe Benefits	Sub-Total	Supervision	Sub-Total	A&G Overhead	Total
	Customer Accounting Costs							
5.1	Billing	56.33	0.09	56.42	2.60	59.02	11.44	70.46
5.2	Service & Billing Enquiry	27.58	0.02	27.60	1.27	28.87	5.60	34.46
5.3	Meter Reading	9.55	0.02	9.57	0.44	10.01	1.94	11.95
5.4	Credit & Collection	17.73	0.02	17.75	0.82	18.56	3.60	22.16
5.5	Sub-total	111.19	0.14	111.33	5.13	116.46	22.58	139.04
5.6	Supervision	4.40	0.73	5.13	(5.13)	0.00	0.00	0.00
5.7	Uncollectible Accounts	15.10	0.00	15.10	0.00	15.10	2.93	18.03
5.	Total Customer Accounting	130.69	0.88	131.56	0.00	131.56	25.50	157.07
6.	**Fringe Benefits**	36.16	(36.16)	0.00	0.00	0.00	0.00	0.00
7.	**Admin & Gen Overhead**	56.21	9.62	65.84	0.00	65.84	(65.84)	0.00
8.	Sub-total A&G and F/B	92.37	(26.54)	65.84	0.00	65.84	(65.84)	0.00
9.	**Total Operating & Maintenance**	2,539.63	0.00	2,539.63	(0.00)	2,539.63	0.00	2,539.63
10.	Deferred Tax	9.20	0.00	9.20	0.00	9.20	0.00	9.20
11.	Fixed Financing Costs	1.30	0.00	1.30	0.00	1.30	0.00	1.30
12.	**TOTAL O&M EXPENSE**	2,550.13	0.00	2,550.13	(0.00)	2,550.13	0.00	2,550.13

CLASSIFICATION OF RATE BASE
DEC. 31, 2007
(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
				GAS SUPPLY											
				PRODUCT COSTS		LOAD BALANCING			STORAGE COSTS			DISTRIBUTION COSTS			
Item No.	Description	Total	Specific Classes	Winter Commodity	Annual Commodity	Peak	Seasonal	Annual	Deliverability	Space	Winter	TP Capacity	HP Capacity	LP Capacity	Commodity
	GAS SUPPLY														
1.	Gas Supply	630.25	0.00	0.00	17.06	0.00	613.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09
2.	Storage	25.85	0.00	0.00	0.00	0.00	0.00	0.00	12.66	13.19	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION														
3.	Mains	1,347.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	289.60	103.29	524.95	0.00
4.	Distribution Reg.	81.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.60	9.13	46.40	0.00
	CUSTOMER														
5.	Sales Station	85.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6.	Meters	235.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.	Services	1,115.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Rental Equipment	7.93	5.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9.	Sales/Marketing	14.51	1.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.99	0.71	3.60	0.00
10.	Customer Accounting	(8.20)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11.	GST Revenue	(14.53)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12.	**Sub-total**	3,520.71	7.52	0.00	17.06	0.00	613.10	0.00	12.66	13.19	0.00	317.18	113.13	574.95	0.09
13.	Unidentifiable	24.50	0.05	0.00	0.12	0.00	4.25	0.00	0.09	0.09	0.00	2.20	0.78	3.99	0.00
14	Entrac	12.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	**Total Classified**	3,557.65	7.57	0.00	17.18	0.00	617.35	0.00	12.75	13.28	0.00	319.38	113.91	578.94	0.09

CLASSIFICATION OF RATE BASE
DEC. 31, 2007

(millions of dollars)

		Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col. 22	Col. 23	Col. 24	Col. 25	Col. 26
		CUSTOMER RELATED INVESTMENTS					NUMBER OF CUSTOMERS						
Item No.	Description	Meters	Sales Stations	Services	Customer Plant	Rentals	Commercial/ Industrial	Contracts	Direct Purchase	Total	Readings Processed	Entrac	GST Revenue
	GAS SUPPLY												
1.	Gas Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.	Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION												
3.	Mains	0.00	0.00	0.00	429.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	Distribution Reg.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CUSTOMER												
5.	Sales Station	0.00	85.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6.	Meters	235.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.	Services	0.00	0.00	1,115.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Rental Equipment	0.00	0.00	0.00	0.00	2.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9.	Sales/Marketing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.30	0.00	0.00	0.00
10.	Customer Accounting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(8.20)	0.00	0.00	0.00
11.	GST Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(14.53)
12.	**Sub-total**	235.58	85.38	1,115.47	429.51	2.31	0.00	0.00	0.00	(1.90)	0.00	0.00	(14.53)
13.	Unidentifiable	1.63	0.59	7.73	2.98	0.02	0.00	0.00	0.00	(0.01)	0.00	0.00	0.00
14	Entrac	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.43	0.00
15	**Total Classified**	237.21	85.97	1,123.20	432.48	2.33	0.00	0.00	0.00	(1.91)	0.00	12.43	(14.53)

CLASSIFICATION OF NET INVESTMENT
DEC. 31, 2007

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16
				GAS SUPPLY													
				PRODUCT COSTS		LOAD BALANCING					STORAGE COSTS			DISTRIBUTION COSTS			
Item No.	Description	Total	Specific Classes	Winter Commodity	Annual Commodity	Peak	Seasonal	Annual	DSM Peak	DSM Annual	Deliverability	Space	Winter	TP Capacity	HP Capacity	LP Capacity	Commodity
	GAS SUPPLY																
1.	Gas Supply	(3.12)	0.00	0.00	0.02	0.00	0.62	(3.74)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.02)
2.	Storage	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION																
3.	Mains	118.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.55	9.11	46.32	0.00
4.	Distribution Reg.	9.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.88	1.03	5.21	0.00
	CUSTOMER																
5.	Sales Station	8.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6.	Meters	9.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.	Services	98.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Rental Equipment	(0.24)	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9.	Sales/Marketing	1.17	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.06	0.29	0.00
10.	Customer Accounting	(9.64)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11.	**Sub-total**	233.02	0.48	0.00	0.02	0.00	0.62	(3.74)	0.00	0.00	0.09	0.10	0.00	28.59	10.20	51.82	(0.02)
12.	Unidentifiable	4.23	0.01	0.00	0.02	0.00	0.73	0.00	0.00	0.00	0.02	0.02	0.00	0.38	0.14	0.69	0.00
13	Entrac	4.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14.	**Total Classified**	242.23	0.49	0.00	0.04	0.00	1.35	(3.74)	0.00	0.00	0.11	0.11	0.00	28.97	10.33	52.51	(0.02)

CLASSIFICATION OF NET INVESTMENT
DEC. 31, 2007

(millions of dollars)

		Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col. 22	Col. 23	Col. 24	Col. 25	Col. 26	Col.27
		CUSTOMER RELATED INVESTMENTS					NUMBER OF CUSTOMERS					
Item No.	Description	Meters	Sales Stations	Services	Customer Plant	Rentals	Commercial/ Industrial	Contracts	Direct Purchase	Total	Readings Processed	Entrac
	GAS SUPPLY											
1.	Gas Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.	Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION											
3.	Mains	0.00	0.00	0.00	37.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	Distribution Reg.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CUSTOMER											
5.	Sales Station	0.00	8.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6.	Meters	9.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.	Services	0.00	0.00	98.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Rental Equipment	0.00	0.00	0.00	0.00	(0.57)	0.00	0.00	0.00	0.00	0.00	0.00
9.	Sales/Marketing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.51	0.00	0.00
10.	Customer Accounting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(9.64)	0.00	0.00
11.	**Sub-total**	9.77	8.27	98.62	37.90	(0.57)	0.00	0.00	0.00	(9.13)	0.00	0.00
12.	Unidentifiable	0.28	0.10	1.33	0.51	0.00	0.00	0.00	0.00	(0.00)	0.00	0.00
13	Entrac	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.98
14.	**Total Classified**	10.05	8.37	99.96	38.41	(0.57)	0.00	0.00	0.00	(9.13)	0.00	4.98

CLASSIFICATION OF O&M COSTS
DEC. 31, 2007
(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col.8	Col. 9	Col. 10	Col. 11	Col. 12
				GAS SUPPLY									
				PRODUCT COSTS				LOAD BALANCING			STORAGE COSTS		
Item No.	Description	Total	Specific Classes	Winter Commodity	Annual Commodity	System Gas	Bad Debt Commodity	Peak	Seasonal	Transportation Annual	Deliverability	Space	Winter
	GAS SUPPLY												
1.1	Gas Purchased	2,066.26	0.00	0.00	1,605.90	0.00	0.00	7.64	5.45	432.53	0.00	0.00	0.00
1.2	Stored Gas	131.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	64.37	67.06	0.00
1.3	A&G	12.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.4	System Gas Management	0.88	0.00	0.00	0.00	0.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.5	Direct Purchase Management	1.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.	Total Gas Supply	2,212.92	0.00	0.00	1,605.90	0.88	0.00	7.64	5.45	432.53	64.37	67.06	0.00
	DISTRIBUTION												
	OPERATING COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.1	Chart Processing	3.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.2	District Stations	2.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.3	System Operations	49.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.4	Gas Dispatched	5.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS												
2.5	Dist. System Reg.	0.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Sales Meters	2.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.7	Other Meters	11.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.8	Instruments	3.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.9	Mains	16.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.10	Structures	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.	Total Distribution Costs	95.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CUSTOMER SERVICE												
	OPERATING COSTS												
3.1	Heating Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2	Appliance Inspection	2.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.3	Locks/Unlocks/Exchanges	12.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.4	JC Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.5	JC Revenues	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS												
3.7	Rentals	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.8	Service Lines	4.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Customer Service	19.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SALES/MARKETING												
4.1	Residential	7.15	7.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.2	Commercial	3.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.3	Industrial	4.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.4	Residential/Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.5	General Promotion	5.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.6	NGV Operation	1.83	1.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.7	Contract Administration	4.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.8	DSM - Program	20.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.9	DSM - General	8.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	Total Promotions	55.07	8.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CUSTOMER ACCOUNTING												
5.1	Billing	70.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.2	Enquiry	34.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.3	Readings	11.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.4	Credit	22.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.5	Uncollectibles	18.03	0.00	0.00	0.00	0.00	9.70	0.00	0.00	0.00	0.00	0.00	0.00
5.	Total Customer Accounting	157.07	0.00	0.00	0.00	0.00	9.70	0.00	0.00	0.00	0.00	0.00	0.00
6.	**Total O&M**	2,539.64	8.98	0.00	1,605.90	0.88	9.70	7.64	5.45	432.53	64.37	67.06	0.00
7.	Deferred Taxes	9.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Fixed Financing Costs	1.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9.	**Total O&M Expense**	2,550.14	8.98	0.00	1,605.90	0.88	9.70	7.64	5.45	432.53	64.37	67.06	0.00

CLASSIFICATION OF O&M COSTS
DEC. 31, 2007

(millions of dollars)

		Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col. 22	Col. 23
		DISTRIBUTION COSTS						CUSTOMER RELATED INVESTMENTS				
Item No.	Description	TP Capacity	HP Capacity	LP Capacity	Commodity	Bad Debt Distribution	DSM	Meters	Sales Stations	Services	Customer Plant	Rentals
	GAS SUPPLY											
1.1	Gas Purchased	0.00	0.00	0.00	14.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.2	Stored Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.3	A&G	12.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.4	System Gas Management	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.5	Direct Purchase Management	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.	Total Gas Supply	12.78	0.00	0.00	14.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION											
	OPERATING COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.1	Chart Processing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.2	District Stations	0.75	0.27	1.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.3	System Operations	10.57	3.77	19.17	0.00	0.00	0.00	0.00	0.00	0.00	15.68	0.00
2.4	Gas Dispatched	5.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS											
2.5	Dist. System Reg.	0.24	0.09	0.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Sales Meters	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.16	0.00	0.00	0.00
2.7	Other Meters	0.00	0.00	0.00	0.00	0.00	0.00	11.33	0.00	0.00	0.00	0.00
2.8	Instruments	3.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.9	Mains	2.18	0.78	10.42	0.00	0.00	0.00	0.00	0.00	0.00	3.23	0.00
2.10	Structures	0.06	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.04	0.01	0.00
2.	Total Distribution Costs	22.58	4.90	31.38	0.00	0.00	0.00	11.34	2.16	0.04	18.92	0.00
	CUSTOMER SERVICE											
	OPERATING COSTS											
3.1	Heating Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2	Appliance Inspection	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.3	Locks/Unlocks/Exchanges	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.4	JC Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.5	JC Revenues	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS											
3.7	Rentals	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.8	Service Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.45	0.00	0.00
3.	Total Customer Service	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.45	0.00	0.00
	SALES/MARKETING											
4.1	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.2	Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.3	Industrial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.4	Residential/Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.5	General Promotion	5.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.6	NGV Operation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.7	Contract Administration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.8	DSM - Program	0.00	0.00	0.00	0.00	0.00	20.28	0.00	0.00	0.00	0.00	0.00
4.9	DSM - General	0.00	0.00	0.00	0.00	0.00	8.16	0.00	0.00	0.00	0.00	0.00
4.	Total Promotions	5.33	0.00	0.00	0.00	0.00	28.45	0.00	0.00	0.00	0.00	0.00
	CUSTOMER ACCOUNTING											
5.1	Billing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.2	Enquiry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.3	Readings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.4	Credit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.5	Uncollectibles	0.00	0.00	0.00	0.00	8.33	0.00	0.00	0.00	0.00	0.00	0.00
5.	Total Customer Accounting	0.00	0.00	0.00	0.00	8.33	0.00	0.00	0.00	0.00	0.00	0.00
6.	**Total O&M**	40.69	4.90	31.38	14.75	8.33	28.45	11.34	2.16	4.48	18.92	0.00
7.	Deferred Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Fixed Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9.	**Total O&M Expense**	40.69	4.90	31.38	14.75	8.33	28.45	11.34	2.16	4.48	18.92	0.00

CLASSIFICATION OF O&M COSTS
DEC. 31, 2007
(millions of dollars)

		Col. 24	Col. 25	Col. 26	Col. 27	Col. 28	Col. 29	Col.30
		NUMBER OF CUSTOMERS						
Item No.	Description	Commercial/ Industrial	Contracts	Direct Purchase	Total	Readings Processed	Deferred Taxes	Fixed Financing
	GAS SUPPLY							
1.1	Gas Purchased	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.2	Stored Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.3	A&G	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.4	System Gas Management	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.5	Direct Purchase Management	0.00	0.00	1.56	0.00	0.00	0.00	0.00
1.	Total Gas Supply	0.00	0.00	1.56	0.00	0.00	0.00	0.00
	DISTRIBUTION							
	OPERATING COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.1	Chart Processing	0.00	0.00	0.00	0.00	3.70	0.00	0.00
2.2	District Stations	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.3	System Operations	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.4	Gas Dispatched	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS							
2.5	Dist. System Reg.	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Sales Meters	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.7	Other Meters	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.8	Instruments	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.9	Mains	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.10	Structures	0.00	0.00	0.00	0.13	0.00	0.00	0.00
2.	Total Distribution Costs	0.00	0.00	0.00	0.13	3.70	0.00	0.00
	CUSTOMER SERVICE							
	OPERATING COSTS							
3.1	Heating Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2	Appliance Inspection	0.00	0.00	0.00	2.77	0.00	0.00	0.00
3.3	Locks/Unlocks/Exchanges	0.00	0.00	0.00	12.22	0.00	0.00	0.00
3.4	JC Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.5	JC Revenues	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS							
3.7	Rentals	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.8	Service Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Customer Service	0.00	0.00	0.00	14.99	0.00	0.00	0.00
	SALES/MARKETING							
4.1	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.2	Commercial	3.37	0.00	0.00	0.00	0.00	0.00	0.00
4.3	Industrial	4.78	0.00	0.00	0.00	0.00	0.00	0.00
4.4	Residential/Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.5	General Promotion	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.6	NGV Operation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.7	Contract Administration	0.00	4.16	0.00	0.00	0.00	0.00	0.00
4.8	DSM - Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.9	DSM - General	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	Total Promotions	8.14	4.16	0.00	0.00	0.00	0.00	0.00
	CUSTOMER ACCOUNTING							
5.1	Billing	0.00	0.00	0.00	70.46	0.00	0.00	0.00
5.2	Enquiry	0.00	0.00	0.00	34.46	0.00	0.00	0.00
5.3	Readings	0.00	0.00	0.00	0.00	11.95	0.00	0.00
5.4	Credit	0.00	0.00	0.00	22.16	0.00	0.00	0.00
5.5	Uncollectibles	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.	Total Customer Accounting	0.00	0.00	0.00	127.09	11.95	0.00	0.00
6.	**Total O&M**	8.14	4.16	1.56	142.21	15.64	0.00	0.00
7.	Deferred Taxes	0.00	0.00	0.00	0.00	0.00	9.20	0.00
8.	Fixed Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	1.30
9.	**Total O&M Expense**	8.14	4.16	1.56	142.21	15.64	9.20	1.30

ALLOCATION OF RATE BASE

DEC. 31, 2007

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 RATE BASE	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col. 10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300	Col. 14 RATE 305	Col. 15 FACTORS EXHIBIT G2.6.3 *
	SUPPLY COST															
	PRODUCT COSTS															
1.1	Annual Commodity	17.18	10.00	5.23	0.02	0.79	0.18	0.15	0.00	0.02	0.15	0.21	0.43	0.00	0.00	1.1
1	Total Gas Cost	17.18	10.00	5.23	0.02	0.79	0.18	0.15	0.00	0.02	0.15	0.21	0.43	0.00	0.00	
	PIPELINE TRANS.															
2.1	Peak	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.1
2.2	Seasonal	617.35	288.36	206.31	0.00	74.61	10.33	3.74	0.00	0.00	10.88	15.45	7.68	0.00	0.00	3.2
2.3	Annual	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.2
2	Total Pipeline Trans. Cost	617.35	288.36	206.31	0.00	74.61	10.33	3.74	0.00	0.00	10.88	15.45	7.68	0.00	0.00	
	FACILITIES' COSTS															
	STORAGE FACILITIES															
3.1	Deliverability	12.75	6.28	4.65	0.00	1.55	0.09	0.01	0.00	0.00	0.00	0.00	0.17	0.00	0.00	3.1
3.2	Space	13.28	6.20	4.44	0.00	1.60	0.22	0.08	0.00	0.00	0.23	0.33	0.17	0.00	0.00	3.2
3	Total Storage	26.03	12.48	9.09	0.00	3.15	0.32	0.09	0.00	0.00	0.23	0.33	0.33	0.00	0.00	
	DISTRIBUTION FACILITIES															
4.1	Capacity TP	319.38	143.70	104.19	0.06	38.25	7.59	8.50	9.61	0.02	2.26	1.09	4.10	0.00	0.00	2.1
4.2	Capacity HP	113.91	54.06	39.20	0.02	14.39	2.86	2.01	0.00	0.01	0.85	0.41	0.00	0.00	0.10	2.2
4.3	Capacity LP	578.94	275.67	199.87	0.11	73.38	14.56	8.37	0.00	0.04	4.34	2.09	0.00	0.00	0.50	2.3
4.4	Commodity	0.09	0.03	0.02	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.00	1.3
4.5	Customer Plant	432.48	396.44	35.42	0.01	0.47	0.07	0.01	0.00	0.01	0.04	0.01	0.00	0.00	0.00	2.4
4	Total Distribution	1,444.80	869.91	378.70	0.20	126.51	25.08	18.91	9.61	0.08	7.50	3.60	4.10	0.00	0.60	
	CUSTOMER RELATED															
5.1	Meters	237.21	135.98	87.70	0.10	9.63	1.65	0.38	0.05	0.32	1.07	0.32	0.00	0.00	0.01	4.1
5.2	Sales Stations	85.97	5.62	61.34	0.07	11.00	2.78	0.60	0.00	1.20	1.44	1.88	0.00	0.00	0.06	4.2
5.3	Services	1,123.20	990.39	126.27	0.06	4.27	0.79	0.32	0.00	0.15	0.57	0.39	0.00	0.00	0.01	4.3
5.4	Rentals	2.33	0.47	1.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.4
5.5	Comm./Ind. Customers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.6
5.6	Contracts	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.7
5.7	Direct Purchase	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.11
5.8	Total Customers	(1.91)	(1.75)	(0.16)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	0.00	(0.00)	4.5
5.9	Specific Classes	7.57	2.09	0.69	4.75	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
5.10	Readings Processed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.8 & 4.9
5.11	GST Revenue	(14.53)	(8.45)	(4.43)	(0.02)	(0.67)	(0.15)	(0.13)	0.00	(0.02)	(0.13)	(0.18)	(0.36)	0.00	0.00	1.1
5	Total Customer Related	1,439.85	1,124.35	273.29	4.96	24.23	5.06	1.20	0.05	1.65	2.96	2.41	(0.36)	0.00	0.08	
6	Entrac	12.43	8.07	2.17	0.00	0.74	0.33	0.48	0.00	0.03	0.13	0.39	0.08	0.00	0.00	
7	**Total Rate Base**	3,557.65	2,313.16	874.80	5.19	230.03	41.29	24.57	9.66	1.78	21.86	22.38	12.27	0.00	0.67	

* G2.6.3 refers to Exhibit G2, Tab 6, Schedule 3.

ALLOCATION OF RETURN & TAXES

December 31, 2007

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 RATE BASE	Col. 2 RETURN & TAXES	Col. 3 RATE 1	Col. 4 RATE 6	Col. 5 RATE 9	Col. 6 RATE 100	Col. 7 RATE 110	Col. 8 RATE 115	Col. 9 RATE 125	Col. 10 RATE 135	Col. 11 RATE 145	Col. 12 RATE 170	Col. 13 RATE 200	Col. 14 RATE 300	Col. 15 RATE 305
	SUPPLY COST															
	PRODUCT COSTS															
1.1	Annual Commodity	17.18	1.47	0.86	0.45	0.00	0.07	0.02	0.01	0.00	0.00	0.01	0.02	0.04	0.00	0.00
1	Total Gas Cost	17.18	1.47	0.86	0.45	0.00	0.07	0.02	0.01	0.00	0.00	0.01	0.02	0.04	0.00	0.00
	PIPELINE TRANS.															
2.1	Peak	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.2	Seasonal	617.35	52.85	24.69	17.66	0.00	6.39	0.88	0.32	0.00	0.00	0.93	1.32	0.66	0.00	0.00
2.3	Annual	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	Total Pipeline Trans. Cost	617.35	52.85	24.69	17.66	0.00	6.39	0.88	0.32	0.00	0.00	0.93	1.32	0.66	0.00	0.00
	FACILITIES' COSTS															
	STORAGE FACILITIES															
3.1	Deliverability	12.75	1.09	0.54	0.40	0.00	0.13	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
3.2	Space	13.28	1.14	0.53	0.38	0.00	0.14	0.02	0.01	0.00	0.00	0.02	0.03	0.01	0.00	0.00
3	Total Storage	26.03	2.23	1.07	0.78	0.00	0.27	0.03	0.01	0.00	0.00	0.02	0.03	0.03	0.00	0.00
	DISTRIBUTION FACILITIES															
4.1	Capacity TP	319.38	27.34	12.30	8.92	0.01	3.28	0.65	0.73	0.82	0.00	0.19	0.09	0.35	0.00	0.00
4.2	Capacity HP	113.91	9.75	4.63	3.36	0.00	1.23	0.24	0.17	0.00	0.00	0.07	0.04	0.00	0.00	0.01
4.3	Capacity LP	578.94	49.57	23.60	17.11	0.01	6.28	1.25	0.72	0.00	0.00	0.37	0.18	0.00	0.00	0.04
4.4	Commodity	0.09	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.5	Customer Plant	432.48	37.03	33.94	3.03	0.00	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	Total Distribution	1,444.80	123.70	74.48	32.42	0.02	10.83	2.15	1.62	0.82	0.01	0.64	0.31	0.35	0.00	0.05
	CUSTOMER RELATED															
5.1	Meters	237.21	20.31	11.64	7.51	0.01	0.82	0.14	0.03	0.00	0.03	0.09	0.03	0.00	0.00	0.00
5.2	Sales Stations	85.97	7.36	0.48	5.25	0.01	0.94	0.24	0.05	0.00	0.10	0.12	0.16	0.00	0.00	0.00
5.3	Services	1,123.20	96.16	84.79	10.81	0.00	0.37	0.07	0.03	0.00	0.01	0.05	0.03	0.00	0.00	0.00
5.4	Rentals	2.33	0.20	0.04	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.5	Comm./Ind. Customers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.6	Contracts	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.7	Direct Purchase	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.8	Total Customers	(1.91)	(0.16)	(0.15)	(0.01)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	0.00	(0.00)
5.9	Specific Classes	7.57	0.65	0.18	0.06	0.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.10	Readings Processed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.11	GST Revenue	(14.53)	(1.24)	(0.72)	(0.38)	(0.00)	(0.06)	(0.01)	(0.01)	0.00	(0.00)	(0.01)	(0.02)	(0.03)	0.00	0.00
5	Total Customer Related	1,439.85	123.27	96.26	23.40	0.42	2.07	0.43	0.10	0.00	0.14	0.25	0.21	(0.03)	0.00	0.01
6	Entrac	12.43	1.06	0.69	0.19	0.00	0.06	0.03	0.04	0.00	0.00	0.01	0.03	0.01	0.00	0.00
7	**Total Facilities**	3,557.65	304.59	198.04	74.90	0.44	19.69	3.53	2.10	0.83	0.15	1.87	1.92	1.05	0.00	0.06

ALLOCATION OF TOTAL COST OF SERVICE
December 31, 2007

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 O&M COSTS	Col. 2 NET INV. COSTS	Col. 3 TOTAL	Col. 4 RATE 1	Col. 5 RATE 6	Col. 6 RATE 9	Col. 7 RATE 100	Col. 8 RATE 110	Col. 9 RATE 115	Col. 10 RATE 125	Col. 11 RATE 135	Col. 12 RATE 145	Col. 13 RATE 170	Col. 14 RATE 200	Col. 15 RATE 300	Col. 16 RATE 305	Col. 17 DIRECT PURCHASE	ALLOCATION FACTORS EXHIBIT G2.6.3 *
	SUPPLY COSTS																		
	PRODUCT COSTS																		
1.1	Annual Commodity	1,605.90	0.04	1,605.94	934.35	489.19	1.83	74.00	16.96	14.12	0.00	1.77	13.94	19.46	40.31	0.00	0.00	0.00	1.1
1.2	Bad Debt Commodity	9.70	0.00	9.70	4.72	4.82	0.00	0.12	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	
1.3	System Gas Fee	0.88	0.00	0.88	0.51	0.27	0.00	0.04	0.01	0.01	0.00	0.00	0.01	0.01	0.02	0.00	0.00	0.00	1.5
1	Total Gas Cost	1,616.48	0.04	1,616.52	939.58	494.28	1.83	74.16	16.97	14.13	0.00	1.77	13.99	19.47	40.33	0.00	0.00	0.00	
	PIPELINE TRANS.																		
2.1	Peak	7.64	0.00	17.50	8.62	6.38	0.00	2.12	0.13	0.02	0.00	0.00	0.00	0.00	0.23	0.00	0.00	0.00	3.1
2.2	Seasonal	5.45	1.35	6.81	3.18	2.28	0.00	0.82	0.11	0.04	0.00	0.00	0.12	0.17	0.08	0.00	0.00	0.00	3.2
2.3	Annual - Transportation	432.53	0.00	432.53	165.11	115.90	0.27	51.16	22.88	33.43	0.00	2.04	9.27	26.91	5.56	0.00	0.00	0.00	1.2
2.4	Seasonal Credit	0.00	0.00	(9.86)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.94)	(8.80)	(0.12)	0.00	0.00	0.00	
2.5	TS Revenue	0.00	(3.74)	(3.74)	(1.43)	(1.00)	(0.00)	(0.44)	(0.20)	(0.29)	0.00	(0.02)	(0.08)	(0.23)	(0.05)	0.00	0.00	0.00	1.2
2	Total Pipeline Trans. Cost	445.62	(2.39)	443.23	175.48	123.55	0.27	53.66	22.93	33.19	0.00	2.03	8.37	18.05	5.70	0.00	0.00	0.00	
	FACILITIES' COSTS																		
	STORAGE FACILITIES																		
3.1	Deliverability	64.37	0.11	64.95	31.99	23.68	0.00	7.88	0.47	0.07	0.00	0.00	0.00	0.00	0.85	0.00	0.00	0.00	3.1
3.2	Space	67.06	0.11	67.17	31.37	22.45	0.00	8.12	1.12	0.41	0.00	0.00	1.18	1.68	0.84	0.00	0.00	0.00	3.2
3.3	Seasonal Credit	0.00	0.00	(0.47)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.47)	0.00	0.00	0.00	0.00	0.00	0.00	
3	Total Storage	131.43	0.22	131.65	63.36	46.13	0.00	16.00	1.60	0.47	0.00	(0.47)	1.18	1.68	1.69	0.00	0.00	0.00	
	DISTRIBUTION FACILITIES																		
4.1	Capacity TP	40.69	28.97	69.66	31.34	22.73	0.01	8.34	1.66	1.85	2.10	0.00	0.49	0.24	0.90	0.00	0.00	0.00	2.1
4.2	Capacity HP	4.90	10.33	15.24	7.23	5.24	0.00	1.92	0.38	0.27	0.00	0.00	0.11	0.05	0.00	0.00	0.01	0.00	2.2
4.3	Capacity LP	31.38	52.51	83.90	39.95	28.96	0.02	10.63	2.11	1.21	0.00	0.01	0.63	0.30	0.00	0.00	0.07	0.00	2.3
4.4	Commodity	14.75	(0.02)	14.73	5.61	3.94	0.01	1.74	0.78	1.14	0.00	0.07	0.31	0.91	0.19	0.00	0.04	0.00	1.3
4.5	Bad Debt Distribution	8.33	0.00	8.33	4.00	4.13	0.00	0.15	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	
4.6	Customer Plant	18.92	38.41	57.33	52.56	4.70	0.00	0.06	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	2.4
4.7	DSM - Program	20.28	0.00	20.28	10.28	1.90	0.00	3.60	0.90	0.94	0.00	0.00	0.84	1.83	0.00	0.00	0.00	0.00	
4.8	DSM - General	8.16	0.00	8.16	2.47	1.08	0.00	2.05	0.51	0.53	0.00	0.00	0.48	1.04	0.00	0.00	0.00	0.00	
4	Total Distribution	147.43	130.21	277.64	153.44	72.68	0.04	28.50	6.34	5.94	2.10	0.09	2.92	4.38	1.08	0.00	0.12	0.00	
	CUSTOMER RELATED																		
5.1	Meters	11.34	10.05	21.39	12.26	7.91	0.01	0.87	0.15	0.03	0.00	0.03	0.10	0.03	0.00	0.00	0.00	0.00	4.1
5.2	Sales Stations	2.16	8.37	10.53	0.69	7.51	0.01	1.35	0.34	0.07	0.00	0.15	0.18	0.23	0.00	0.00	0.01	0.00	4.2
5.3	Services	4.48	99.96	104.44	92.09	11.74	0.01	0.40	0.07	0.03	0.00	0.01	0.05	0.04	0.00	0.00	0.00	0.00	4.3
5.4	Rentals	0.00	(0.57)	(0.57)	(0.11)	(0.45)	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.4
5.5	Comm./Ind. Customers	8.14	0.00	8.14	0.00	8.00	0.00	0.11	0.02	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	4.6
5.7	Direct Purchase	1.56	0.00	1.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.56	4.11
5.8	Total Customers	142.21	(9.13)	133.08	121.99	10.90	0.00	0.15	0.02	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	4.5
5.9	Specific Classes	8.98	0.49	9.47	7.40	0.96	0.74	0.00	0.19	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
5.10	Readings Processed	15.64	0.00	15.64	11.00	1.95	0.01	2.03	0.30	0.06	0.00	0.04	0.20	0.06	0.00	0.00	0.00	0.00	4.8 & 4.9
5.11	Deferred Tax	9.20	0.00	9.20	5.98	2.26	0.01	0.59	0.11	0.06	0.02	0.00	0.06	0.06	0.03	0.00	0.00	0.00	5
5.12	Financing Costs	1.30	0.00	1.30	0.85	0.32	0.00	0.08	0.02	0.01	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	5
5.13	Entrac	0.00	4.98	4.98	3.23	0.87	0.00	0.30	0.13	0.19	0.00	0.01	0.05	0.16	0.03	0.00	0.00	0.00	
5	Total Customer Related	209.18	114.15	323.33	255.37	51.98	0.79	9.08	1.80	0.76	0.04	0.31	0.94	0.63	0.07	0.00	0.01	1.56	
6.1	Return	216.15	0.00	216.15	140.54	53.15	0.32	13.98	2.51	1.49	0.59	0.11	1.33	1.36	0.75	0.00	0.04	0.00	5
6.2	Taxes	88.44	0.00	88.44	57.51	21.75	0.13	5.72	1.03	0.61	0.24	0.04	0.54	0.56	0.30	0.00	0.02	0.00	5
6	Return and Taxes	304.59	0.00	304.59	198.04	74.90	0.44	19.69	3.53	2.10	0.83	0.15	1.87	1.92	1.05	0.00	0.06	0.00	
7	Total Facilities	792.63	244.58	1,037.21	670.22	245.68	1.28	73.28	13.27	9.28	2.96	0.08	6.91	8.61	3.89	0.00	0.20	1.56	
8	**Total Cost of Service**	2,854.73	242.23	3,096.96	1,785.28	863.51	3.38	201.10	53.16	56.60	2.96	3.87	29.27	46.13	49.93	0.00	0.20	1.56	

RATE BASE
FUNCTIONALIZATION FACTORS
DECEMBER 31, 2007

Item No.		Col. 1 Total	Col. 2 Gas Supply	Col. 3 Storage	Col. 4 Sales Stations	Col. 5 Distribution Measurement	Col. 6 Services	Col. 7 Mains	Col. 8 Meters	Col. 9 Rental Equipment	Col. 10 Sales Promotion	Col. 11 Customer Accounting	Col. 12 Unidenti-fiable	Col. 13 Entrac
	Gas Supply													
1.1	Gas Supply	1.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Distribution Plant													
2.1	Land (incl offers to buy)	1.000	0.010	0.000	0.005	0.002	0.119	0.096	0.002	0.000	0.161	0.426	0.179	0.000
2.2	Structures & Improvements	1.000	0.010	0.000	0.005	0.002	0.119	0.096	0.002	0.000	0.161	0.426	0.179	0.000
2.3	Mains	1.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000
2.4	Meas. Reg. & Telemtrng	1.000	0.000	0.000	0.532	0.468	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2.5	Services	1.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2.6	Meters	1.000	0.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000
	General Plant													
3.1	Land (incl offers to buy)	1.000	0.000	0.000	0.000	0.000	0.336	0.045	0.000	0.000	0.126	0.353	0.140	0.000
3.2	Structures & Improvements	1.000	0.000	0.000	0.000	0.000	0.336	0.045	0.000	0.000	0.126	0.353	0.140	0.000
3.3	Office Furniture & Equip.	1.000	0.001	0.001	0.001	0.123	0.161	0.200	0.046	0.017	0.024	0.031	0.394	0.000
3.4	Transportation Equipment	1.000	0.000	0.000	0.000	0.002	0.297	0.669	0.000	0.000	0.033	0.000	0.000	0.000
3.5	Heavy Work Equipment	1.000	0.000	0.000	0.000	0.002	0.297	0.669	0.000	0.000	0.033	0.000	0.000	0.000
3.6	Tools & Work Equip.	1.000	0.000	0.000	0.000	0.000	0.500	0.500	0.000	0.000	0.000	0.000	0.000	0.000
3.7	Rental Equip.	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000
3.8	Communication Equip.	1.000	0.014	0.000	0.008	0.283	0.086	0.125	0.000	0.001	0.094	0.171	0.218	0.000
3.9	Compressors	1.000	0.000	0.000	0.000	0.002	0.297	0.669	0.000	0.000	0.033	0.000	0.000	0.000
3.10	Computer Equip.	1.000	0.024	0.003	0.023	0.085	0.161	0.261	0.085	0.002	0.009	0.231	0.116	0.000
3.11	S.I.M	1.000	0.037	0.000	0.026	0.023	0.154	0.198	0.004	0.040	0.051	0.062	0.405	0.000
3.12	Entrac	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.000
4.	Other Plant	1.000	0.000	0.000	0.000	0.000	0.436	0.564	0.000	0.000	0.000	0.000	0.000	0.000
5.	Plant Held for Future Use	1.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

WORKING CAPITAL AND
NET INVESTMENT
FUNCTIONALIZATION FACTORS
DECEMBER 31, 2007

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13
Item No.		Total	Gas Supply	Storage	Sales Stations	Distribution Measurement	Services	Mains	Meters	Rental Equipment	Sales/ Marketing	Customer Accounting	Unidenti- fiable	GST Revenue
1.	**Prepaid Expenses**	1.000	0.000	0.000	0.000	0.000	0.123	0.123	0.000	0.000	0.009	0.000	0.746	0.000
	Materials & Supplies													
2.1	Pipe	1.000	0.000	0.000	0.000	0.000	0.227	0.773	0.000	0.000	0.000	0.000	0.000	0.000
2.2	Tools	1.000	0.000	0.000	0.000	0.000	0.500	0.500	0.000	0.000	0.000	0.000	0.000	0.000
2.3	Construction Supplies	1.000	0.000	0.000	0.000	0.000	0.500	0.500	0.000	0.000	0.000	0.000	0.000	0.000
	Net Investments													
3.	Municipal Taxes	1.000	0.001	0.000	0.004	0.004	0.314	0.626	0.000	0.000	0.011	0.028	0.012	0.000
4.	Capital Taxes	1.000	0.001	0.000	0.004	0.004	0.314	0.626	0.000	0.000	0.011	0.028	0.012	0.000

CLASSIFICATION OF GAS COSTS TO OPERATIONS

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
		System Commodity			Load Balancing							
					Storage			Pipeline				
Item No.	Description	Annual Volumes (10³m³)	Variable Unit Rate $/(10³m³)	Variable Cost $(000)	Deliver-ability $(000)	Seasonal Space $(000)	Winter $(000)	Peak $(000)	Seasonal $(000)	Annual $(000)	Dist'n. Commodity $(000)	Total $(000)
	Purchases and Receipts											
1.1	Long-Term	1,460.1	338.894	494.8	0.0	0.0	0.0	0.0	0.0	6.8	0.0	501.6
1.2	Western Buy/Sell	8,628.7	338.894	2,924.2	0.0	0.0	0.0	0.0	0.0	37.6	0.0	2,961.8
1.3	Ontario Buy.Sell	0.0	338.894	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.4	Short-Term Annual	0.0	338.894	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.5	Short-Term Peak	43,660.0	338.894	14,796.1	0.0	0.0	0.0	7,757.8	0.0	0.0	0.0	22,554.0
1.6	Discretionary Western & US	4,264,402.2	338.894	1,445,180.3	0.0	0.0	0.0	0.0	0.0	37,886.5	0.0	1,483,066.8
1.7	Discretionary - Ontario	594,009.4	338.894	201,306.2	0.0	0.0	0.0	0.0	5,538.6	8,296.4	0.0	215,141.2
1.	Total Purchases & Receipts	4,912,160.4	338.894	1,664,701.7	0.0	0.0	0.0	7,757.8	5,538.6	46,227.2	0.0	1,724,225.3
	Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1	TCPL FT-Demand System	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	280,676.8	0.0	280,676.8
2.2	TCPL FT-Winter	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.3	Alliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	37,992.1	0.0	37,992.1
2.4	Vector	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	48,984.1	0.0	48,984.1
2.5	Union - M13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.6	U.S. Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.7	Nova	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,658.0	0.0	1,658.0
2.8	Michcon/ANR/Link	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,166.0	0.0	1,166.0
2.	Total Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	370,477.0	0.0	370,477.0
	Other Costs											
3.1	Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22,980.0	0.0	22,980.0
3.2	Delivery Pressure Charge	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.3	Upstream Differential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	Total Other Variable Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22,980.0	0.0	22,980.0
4.	**Total Delivered Supply**	4,912,160.4	0.0	1,664,701.7	0.0	0.0	0.0	7,757.8	5,538.6	439,684.1	0.0	2,117,682.2
5.	**Storage Fluctuation**	(110,159.6)	338.894	(37,332.4)	0.0	0.0	0.0	(79.5)	(56.8)	(4,506.4)	0.0	(41,975.1)
6.	**Gas Costs to Operations**	4,802,000.8	0.0	1,627,369.3	0.0	0.0	0.0	7,678.3	5,481.8	435,177.7	0.0	2,075,707.1
7.	**Storage and Transportation**	0.0	0.0	0.0	63,858.9	66,520.6	0.0	0.0	0.0	0.0	0.0	130,379.5
8.	**Gas Costs-Storage & Trans.**	4,802,000.8	0.0	1,627,369.3	63,858.9	66,520.6	0.0	7,678.3	5,481.8	435,177.7	0.0	2,206,086.6
9.1	UUF Adjustment			(13,415.7)	0.0	0.0	0.0	(22.7)	(16.2)	(1,288.7)	14,743.4	0.0
9.2	LUF Adjustment			(8,053.3)	0.0	0.0	0.0	(15.5)	(11.1)	(975.0)	0.0	(9,054.8)
9.3	Other Costs			0.0	0.0	0.0	0.0	0.0	0.0	(388.7)	0.0	(388.7)
9.	**Total Classified Costs**			1,605,900.3	63,858.9	66,520.6	0.0	7,640.1	5,454.5	432,525.3	14,743.4	2,196,643.1
	GAS COSTS											
10.1	Classification Factors			1,605,900.3	0.0	0.0	0.0	7,640.1	5,454.5	432,525.3	14,743.4	2,066,263.6
10.2	Classification Percentages			77.720%	0.000%	0.000%	0.000%	0.370%	0.264%	20.933%	0.714%	100.000%
	STORAGE											
11.1	Classification Factors				63,858.9	66,520.6	0.0	0.0	0.0	0.0	0.0	130,379.5
11.2	Classification Percentages				48.979%	51.021%	0.000%	0.000%	0.000%	0.000%	0.000%	100.000%

CLASSIFICATION OF
STORAGE AND TRANSPORTATION

($000)

Item No.	Description	Col. 1 Tecumseh O&M	Col. 2 Annual Cost	Col. 3 Deliver-ability	Col. 4 Seasonal Space	Col. 5 Winter	Col. 6 Annual Commodity
	TECUMSEH						
	TRANSMISSION						
1.1	Annual Demand	5,299.5	5,299.5	0.0	5,299.5	0.0	0.0
1.2	Daily Demand	7,956.1	7,956.1	7,956.1	0.0	0.0	0.0
1.3	In/out	7,599.4	7,599.4	0.0	7,599.4	0.0	0.0
1.4	Fuel	6,361.3	6,361.3	0.0	6,361.3	0.0	0.0
1.5	Transactional Services Revenues	(2,363.1)	(2,363.1)	(1,417.9)	(945.2)	0.0	0.0
1.	Total Transmission	24,853.3	24,853.3	6,538.2	18,315.0	0.0	0.0
	STORAGE						
2.1	Annual Demand	6,209.7	6,209.7	0.0	6,209.7	0.0	0.0
2.2	Daily Demand	9,353.2	9,353.2	9,353.2	0.0	0.0	0.0
2.3	In/out	3,002.4	3,002.4	0.0	3,002.4	0.0	0.0
2.4	Transactional Services Revenues	(2,004.9)	(2,004.9)	(1,202.9)	(802.0)	0.0	0.0
2.	Total Storage	16,560.5	16,560.5	8,150.3	8,410.2	0.0	0.0
3.	Total Tecumseh	41,413.7	41,413.7	14,688.5	26,725.2	0.0	0.0
	UNION GAS						
	STORAGE						
4.1	Space		2,722.8	0.0	2,722.8	0.0	0.0
4.2	Peak		4,032.2	4,032.2	0.0	0.0	0.0
4.3	Injection		79.0	0.0	79.0	0.0	0.0
4.4	Withdrawal		74.2	0.0	74.2	0.0	0.0
	Chatham D		125.6	0.0	125.6	0.0	0.0
4.	Total Storage		7,033.8	4,032.2	3,001.6	0.0	0.0
	TRANSMISSION						
5.1	Demand with comp.		52,133.5	26,874.0	25,259.6	0.0	0.0
5.2	Company Production M13		0.0	0.0	0.0	0.0	0.0
5.3	US Trns. C1		0.0	0.0	0.0	0.0	0.0
5.4	Fuel		24,476.6	12,617.3	11,859.3	0.0	0.0
5.5	Interruptible Margin Rebate		(730.3)	(376.5)	(353.8)	0.0	0.0
5.	Total Transportation		75,879.8	39,114.8	36,765.1	0.0	0.0
6.	SNG Premium		0.0	0.0	0.0	0.0	0.0
	DEHYDRATION						
7.1	Demand		739.5	739.5	0.0	0.0	0.0
7.2	Commodity		28.7	0.0	28.7	0.0	0.0
7.	Total Dehydration		768.2	739.5	28.7	0.0	0.0
8.	Total Union		83,681.8	43,886.5	39,795.4	0.0	0.0
	TRANSCANADA						
9.1	STS and Other		5,283.9	5,283.9	0.0	0.0	0.0
9.	Total TransCanada		5,283.9	5,283.9	0.0	0.0	0.0
10.	**TOTAL STORAGE & TRANSP.**	41,413.7	130,379.5	63,858.9	66,520.6	0.0	0.0
11.	**Less Union M13**		0.0	0.0	0.0	0.0	0.0
12.	**Less Union C1**		0.0	0.0	0.0	0.0	0.0
13.	**COST TO OPERATIONS**	41,413.7	130,379.5	63,858.9	66,520.6	0.0	0.0

CLASSIFICATION OF TRANSPORTATION COSTS

($000)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
Item No.	Description	Total	Peak	Seasonal	Annual Delivery	Annual Commodity
	FT TCPL					
1.1	Demand	261,258.5	0.0	0.0	261,258.5	0.0
1.2	Commodity	19,418.3	0.0	0.0	0.0	19,418.3
1.3	Winter	0.0	0.0	0.0	0.0	0.0
	Alliance					
2.1	Demand	37,992.1	0.0	0.0	37,992.1	0.0
2.2	Commodity	0.0	0.0	0.0	0.0	0.0
3	**Vector Demand**	48,984.1	0.0	0.0	48,984.1	0.0
4	**US Transportation**	0.0	0.0	0.0	0.0	0.0
5	**NOVA Demand**	1,658.0	0.0	0.0	1,658.0	0.0
6	**Michcon/ANR/Link**	1,166.0	0.0	0.0	1,166.0	0.0
	OTHER					
7.1	Fuel	22,980.0	0.0	0.0	0.0	22,980.0
7.2	Delivery Pr. Diff	0.0	0.0	0.0	0.0	0.0
7.3	Upstream Diff.	0.0	0.0	0.0	0.0	0.0
8	**Total**	393,457.0	0.0	0.0	351,058.7	42,398.3

ALLOCATION FACTORS
DEC. 31, 2007

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16
	FACTOR TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300	RATE 305	RATE 315	Direct Purchase
COMMODITY RESPONSIBILITY																
1.1 Annual Sales	4,738.7	2,757.0	1,443.5	5.4	218.3	50.0	41.7	0.0	5.2	41.1	57.4	118.9	0.0	0.0	0.0	0.0
1.2 Bundled Annual Deliveries	11,726.3	4,476.3	3,142.1	7.4	1,387.0	620.4	906.2	0.0	55.4	251.2	729.6	150.7	0.0	0.0	0.0	0.0
1.3 Total Annual Deliveries	11,757.6	4,476.3	3,142.1	7.4	1,387.0	620.4	906.2	0.0	55.4	251.2	729.6	150.7	0.0	31.2	0.0	0.0
1.4 Bundled Peak Delivery	96,368.8	44,705.5	32,413.6	18.4	11,900.4	2,360.9	2,643.7	0.0	6.9	704.6	338.4	1,276.5	0.0	0.0	0.0	0.0
1.5 System Gas Sales	4,738.7	2,757.0	1,443.5	5.4	218.3	50.0	41.7	0.0	5.2	41.1	57.4	118.9	0.0	0.0	0.0	0.0
DISTRIBUTION CAPACITY RESPONSIBILITY																
2.1 Delivery Demand TP	99,359.1	44,705.5	32,413.6	18.4	11,900.4	2,360.9	2,643.7	2,990.3	6.9	704.6	338.4	1,276.5	0.0	0.0	0.0	0.0
2.2 Delivery Demand HP	94,195.1	44,705.5	32,413.6	18.4	11,900.4	2,360.9	1,665.7	0.0	6.9	704.6	338.4	0.0	0.0	80.9	0.0	0.0
2.3 Delivery Demand LP	93,887.1	44,705.5	32,413.6	18.4	11,900.4	2,360.9	1,357.6	0.0	6.9	704.6	338.4	0.0	0.0	80.9	0.0	0.0
2.4 Cust. Rel Plant	1,823,258	1,671,317	149,319	32	1,996	287	62	1	37	171	34	1	0	1	0	0.0
STORAGE RESPONSIBILITY																
3.1 Deliverability	48.5	23.9	17.7	0.0	5.9	0.4	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0
3.2 Space	2,770.3	1,294.0	925.8	0.0	334.8	46.3	16.8	0.0	0.0	48.8	69.3	34.5	0.0	0.0	0.0	0.0
CUSTOMER RESPONSIBILITY																
4.1 Meters	345,100.0	197,830.4	127,593.8	140.3	14,015.8	2,394.1	554.4	70.0	462.5	1,560.8	464.2	0.0	0.0	13.7	0.0	0.0
4.2 Sales Stations	146,528.9	9,583.1	104,539.7	125.8	18,741.3	4,730.8	1,018.3	0.0	2,042.8	2,454.8	3,198.2	0.0	0.0	94.1	0.0	0.0
4.3 Services	1,786,400.0	1,575,159.1	200,824.4	91.9	6,785.8	1,263.2	501.2	0.0	233.4	909.3	613.6	0.0	0.0	18.0	0.0	0.0
4.4 Rental Equipment	0.3	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4.5 Total Customer Count	1,823,258	1,671,317	149,319	32	1,996	287	62	1	37	171	34	1	0	1	0	0.0
4.6 Comm/Ind. Customer Count	151,941	0	149,319	32	1,996	287	62	1	37	171	34	1	0	1	0	0.0
4.7 Contracts	2,590	0	0	0	1,996	287	62	1	37	171	34	1	0	1	0	0.0
4.8 Chart Readings non AMR per Year	59,996	0	59,348	648	0	0	0	0	0	0	0	0	0	0	0	0.0
4.9 Chart Readings AMR per Year	3,714	0	1,009	9	2,042	297	62	1	38	199	56	0	0	1	0	0.0
4.10 Meter Readings per Year	10,894,986	10,027,902	867,084	0	0	0	0	0	0	0	0	0	0	0	0	0.0
4.11 Direct Purchase Customers	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.0
4.12 Asset Usage Allocator	93.4	71.1	16.4	0.0	3.2	0.9	0.7	0.0	0.0	0.5	0.3	0.2	0.0	0.0	0.0	0.0
5. Rate Base	3,557.6	2,313.2	874.8	5.2	230.0	41.3	24.6	9.7	1.8	21.9	22.4	12.3	0.0	0.7	0.0	0.0

ALLOCATION PERCENTAGES
DEC. 31, 2007

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
	FACTOR TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300	RATE 305	Direct Purchase
COMMODITY RESPONSIBILITY															
1.1 Annual Sales	1.0000	0.5818	0.3046	0.0011	0.0461	0.0106	0.0088	0.0000	0.0011	0.0087	0.0121	0.0251	0.0000	0.0000	0.0000
1.2 Bundled Annual Deliveries	1.0000	0.3817	0.2680	0.0006	0.1183	0.0529	0.0773	0.0000	0.0047	0.0214	0.0622	0.0128	0.0000	0.0000	0.0000
1.3 Total Annual Deliveries	1.0000	0.3807	0.2672	0.0006	0.1180	0.0528	0.0771	0.0000	0.0047	0.0214	0.0621	0.0128	0.0000	0.0027	0.0000
1.4 Bundled Peak Delivery	1.0000	0.4639	0.3363	0.0002	0.1235	0.0245	0.0274	0.0000	0.0001	0.0073	0.0035	0.0132	0.0000	0.0000	0.0000
1.5 System Gas Sales	1.0000	0.5818	0.3046	0.0011	0.0461	0.0106	0.0088	0.0000	0.0011	0.0087	0.0121	0.0251	0.0000	0.0000	0.0000
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	1.0000	0.4499	0.3262	0.0002	0.1198	0.0238	0.0266	0.0301	0.0001	0.0071	0.0034	0.0128	0.0000	0.0000	0.0000
2.2 Delivery Demand HP	1.0000	0.4746	0.3441	0.0002	0.1263	0.0251	0.0177	0.0000	0.0001	0.0075	0.0036	0.0000	0.0000	0.0009	0.0000
2.3 Delivery Demand LP	1.0000	0.4762	0.3452	0.0002	0.1268	0.0251	0.0145	0.0000	0.0001	0.0075	0.0036	0.0000	0.0000	0.0009	0.0000
2.4 Cust. Rel Plant	1.0000	0.9167	0.0819	0.0000	0.0011	0.0002	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
STORAGE RESPONSIBILITY															
3.1 Deliverability	1.0000	0.4925	0.3646	0.0000	0.1214	0.0073	0.0010	0.0000	0.0000	0.0000	0.0000	0.0131	0.0000	0.0000	0.0000
3.2 Space	1.0000	0.4671	0.3342	0.0000	0.1209	0.0167	0.0061	0.0000	0.0000	0.0176	0.0250	0.0124	0.0000	0.0000	0.0000
CUSTOMER RESPONSIBILITY															
4.1 Meters	1.0000	0.5733	0.3697	0.0004	0.0406	0.0069	0.0016	0.0002	0.0013	0.0045	0.0013	0.0000	0.0000	0.0000	0.0000
4.2 Sales Stations	1.0000	0.0654	0.7134	0.0009	0.1279	0.0323	0.0069	0.0000	0.0139	0.0168	0.0218	0.0000	0.0000	0.0006	0.0000
4.3 Services	1.0000	0.8818	0.1124	0.0001	0.0038	0.0007	0.0003	0.0000	0.0001	0.0005	0.0003	0.0000	0.0000	0.0000	0.0000
4.4 Rental Equipment	1.0000	0.2000	0.7999	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.5 Total Customer Count	1.0000	0.9167	0.0819	0.0000	0.0011	0.0002	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
4.6 Comm/Ind. Customer Count	1.0000	0.0000	0.9827	0.0002	0.0131	0.0019	0.0004	0.0000	0.0002	0.0011	0.0002	0.0000	0.0000	0.0000	0.0000
4.7 Contracts	1.0000	0.0000	0.0000	0.0000	0.7707	0.1108	0.0239	0.0004	0.0143	0.0660	0.0131	0.0004	0.0000	0.0004	0.0000
4.8 Chart Readings non AMR per Yea	1.0000	0.0000	0.9892	0.0108	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.9 Chart Readings AMR per Year	1.0000	0.0000	0.2717	0.0024	0.5498	0.0800	0.0167	0.0003	0.0102	0.0536	0.0151	0.0000	0.0000	0.0003	0.0000
4.10 Meter Readings per Year	1.0000	0.9204	0.0796	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.11 Separation Expense Allocator	1.0000	0.7750	0.2250	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.12 Direct Purchase Customers	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0000
4.13 Asset Usage Allocator	1.0000	0.7613	0.1757	0.0003	0.0346	0.0094	0.0076	0.0000	0.0003	0.0054	0.0036	0.0017	0.0000	0.0000	0.0000
5. Rate Base	1.0000	0.6502	0.2459	0.0015	0.0647	0.0116	0.0069	0.0027	0.0005	0.0061	0.0063	0.0034	0.0000	0.0002	0.0000

Allocation of DSM Program and General Costs Including Fringe Benefits and A&G

DEC. 31, 2007

(millions of dollars)

	Total	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300
DSM Program and General Costs	16.99	8.61	1.59	0.00	3.02	0.75	0.78	0.00	0.00	0.70	1.53	0.00	0.00
Fringe Benefits	1.83	0.55	0.24	0.00	0.46	0.11	0.12	0.00	0.00	0.11	0.23	0.00	0.00
A&G	4.62	2.07	0.48	0.00	0.92	0.23	0.24	0.00	0.00	0.21	0.47	0.00	0.00
Total	23.44	11.24	2.32	0.00	4.40	1.09	1.14	0.00	0.00	1.02	2.23	0.00	0.00
Breakdown of DSM Program and General Costs:													
DSM Program Costs	16.99	8.61	1.59	0.00	3.02	0.75	0.78	0.00	0.00	0.70	1.53	0.00	0.00
A&G	3.29	1.67	0.31	0.00	0.58	0.15	0.15	0.00	0.00	0.14	0.30	0.00	0.00
Total	20.28	10.28	1.90	0.00	3.60	0.90	0.94	0.00	0.00	0.84	1.83	0.00	0.00
DSM General Costs	5.01	1.51	0.66	0.00	1.26	0.31	0.33	0.00	0.00	0.29	0.64	0.00	0.00
Fringe Benefits	1.83	0.55	0.24	0.00	0.46	0.11	0.12	0.00	0.00	0.11	0.23	0.00	0.00
A&G	1.33	0.40	0.18	0.00	0.33	0.08	0.09	0.00	0.00	0.08	0.17	0.00	0.00
Total	8.16	2.47	1.08	0.00	2.05	0.51	0.53	0.00	0.00	0.48	1.04	0.00	0.00

TECUMSEH GAS
FUNCTIONALIZATION AND CLASSIFICATION OF RATE BASE
2007 TEST YEAR

($000)

Item No.	Description	Functional Allocation T/C	Pool	Col. 1 Net Investment Avg. of Mnthly Avg.	Col. 2 Transmission & Compression	Col. 3 Pool Storage Space	Col. 4 Net Investment Avg. of Mnthly Avg.	Col. 5	Col. 6	Col. 7 Annual Demand	Col. 8 Daily Demand	Col. 9 Net Investment Avg. of Mnthly Avg.	Col. 10	Col. 11	Col. 12 Annual Demand	Col. 13 Daily Demand
		FUNCTIONALIZATION					CLASSIFICATION: Transmission & Compression					CLASSIFICATION: Pool Storage Space				
1.1	Transmission Lines	100%	0%	9,519.5	9,519.5		9,519.5	40%	60%	3,807.8	5,711.7		40%	60%	0.0	0.0
1.2	Compressor Equipment	100%	0%	54,621.6	54,621.6		54,621.6	40%	60%	21,848.6	32,773.0		40%	60%	0.0	0.0
1.3	Structures & Improvements	100%	0%	7,414.0	7,414.0		7,414.0	40%	60%	2,965.6	4,448.4		40%	60%	0.0	0.0
1.4	Office and Plant Equipment	100%	0%	1,250.1	1,250.1		1,250.1	40%	60%	500.0	750.1		40%	60%	0.0	0.0
1.5	Land	100%	0%	188.7	188.7		188.7	40%	60%	75.5	113.2		40%	60%	0.0	0.0
1.6.1	Allowance for - Mat'ls & Supplies	100%	0%	2,362.3	2,362.3		2,362.3	40%	60%	944.9	1,417.4		40%	60%	0.0	0.0
1.6.2	Working Capital - Working Cash Allow.	100%	0%	1,100.0	1,100.0		1,100.0	40%	60%	440.0	660.0		40%	60%	0.0	0.0
1.7	Provision for LUF	69%	31%		0.0	0.0	0.0	40%	60%	0.0	0.0	0.0	40%	60%	0.0	0.0
1.				76,456.2	76,456.2		76,456.2			30,582.5	45,873.7					
2.1	Field Lines	0%	100%	19,518.3		19,518.3		40%	60%	0.0	0.0	19,518.3	40%	60%	7,807.3	11,711.0
2.2	Wells	0%	100%	14,275.1		14,275.1		40%	60%	0.0	0.0	14,275.1	40%	60%	5,710.0	8,565.1
2.3	Well Equipment	0%	100%	3,638.6		3,638.6		40%	60%	0.0	0.0	3,638.6	40%	60%	1,455.4	2,183.2
2.4	Measuring & Regulating	0%	100%	8,472.1		8,472.1		40%	60%	0.0	0.0	8,472.1	40%	60%	3,388.8	5,083.3
2.5	Gas Storage Rights	0%	100%	22,708.2		22,708.2		40%	60%	0.0	0.0	22,708.2	40%	60%	9,083.3	13,624.9
2.6	Petroleum and Natural Gas Leases	0%	100%			0.0		40%	60%	0.0	0.0	0.0	40%	60%	0.0	0.0
2.7	Base Pressure Gas	0%	100%	40,767.1		40,767.1		40%	60%	0.0	0.0	40,767.1	40%	60%	16,306.8	24,460.3
2.8	Other	0%	100%			0.0	0.0	40%	60%	0.0	0.0	0.0	40%	60%	0.0	0.0
2.				109,379.4		109,379.4						109,379.4			43,751.8	65,627.6
3.	Total			185,835.6	76,456.2	109,379.4	76,456.2			30,582.5	45,873.7	109,379.4			43,751.8	65,627.6
4.	Percentage Allocation			2,369.0	41.142%	58.858%				40.000%	60.000%				40.000%	60.000%

TECUMSEH GAS
FUNCTIONAL ALLOCATION OF COST OF SERVICE
2007 TEST YEAR

Item No.		Col.1 Functional Allocation T/C	Col.2 Pool	Col.3 Utility Return & Expenses	Col.4 Transmission & Compression	Col.5 Pool Storage
RATE BASE RETURN AMOUNT				($000)	($000)	($000)
1.1	Utility Return	40%	60%	15,909.9	6,364.0	9,545.9
1.	Total Return	0%	0%	15,909.9	6,364.0	9,545.9
EXPENSES - OPERATION						
2.1.1	Labour	80%	20%	1,428.7	1,142.9	285.7
2.1.2	Supplies & Other		10%	355.0	319.5	35.5
2.1.3	Hydro	100%	0%	360.8	360.8	
2.1.4	Lease Rentals	0%	100%	1,248.7		1,248.7
2.1.5	Surface Rentals	0%	100%			
2.1.6	Provision for LUF	69%	31%	9,054.8	6,247.8	2,807.0
2.1	Subtotal			12,447.9	8,071.0	4,376.9
MAINTENANCE						
2.2.1	Company	90%	10%	1,798.1	1,618.3	179.8
2.2.2	Contractor	80%	20%	597.0	477.6	119.4
2.2	Subtotal			2,395.1	2,095.9	299.2
ADMINISTRATIVE & GENERAL						
2.3.1	General Office	80%	20%	1,975.4	1,580.3	395.1
2.3.2	Service Fees	80%	20%	1,013.0	810.4	202.6
2.3.3	Overhead Capitalized	80%	20%	(451.6)	(361.3)	(90.3)
2.3	Subtotal			2,536.8	2,029.4	507.4
DEPRECIATION AND AMORTIZATION						
2.4.1	Depreciation	47%	53%	5,301.1	2,508.5	2,792.6
2.4.2	Amortization	0%	100%	868.3		868.3
2.4	Subtotal			6,169.4	2,508.5	3,660.9
TAXES - OTHER THAN INCOME						
2.5.1	Municipal	80%	20%	1,351.0	1,080.8	270.2
2.5.2	Capital	40%	60%	505.0	202.0	303.0
2.5	Subtotal			1,856.0	1,282.8	573.2
2. TOTAL EXPENSES				25,405.3	15,987.6	9,417.6
3. REVENUE REQUIREMENT BEFORE TAXES				41,315.2	22,351.5	18,963.6

TECUMSEH GAS
CLASSIFICATION OF COST OF SERVICE
2007 TEST YEAR

($000)

Item No.		Functional Allocation T/C	Pool	Utility Return & Expenses	Transmission & Compression	Storage Space	Col. 1 Total	Col. 2 Alloc'tn Ann	Col. 3 Dly	Col. 4 Annual Demand	Col. 5 Daily Demand	Col. 6 Commodity	Col. 7 Storage Total	Col. 8 Union Transfer	Col. 9 Net Tecumseh	Col. 10 Alloc'tn Ann	Col. 11 Dly	Col. 12 Annual Demand	Col. 13 Daily Demand	Col. 14 Commodity
							Transmission & Compression						Pool Storage							
	RATE BASE RETURN AMOUNT																			
1.1	Utility Return	40%	60%	15,909.9	6,364.0	9,545.9	6,364.0	40%	60%	2,545.6	3,818.4		9,545.9	0.0	9,545.9	40%	60%	3,818.4	5,727.6	
1.	Total Return			15,909.9	6,364.0	9,545.9	6,364.0			2,545.6	3,818.4		9,545.9	0.0	9,545.9			3,818.4	5,727.6	
	EXPENSES - OPERATION																			
2.1.1	Labour	80%	20%	1,428.7	1,142.9	285.7	1,142.9	40%	60%	457.2	685.7		285.7	16.2	269.5	40%	60%	107.8	161.7	
2.1.2	Supplies & Other	90%	10%	355.0	319.5	35.5	319.5	20%	30%	63.9	95.9	159.7	35.5	2.0	33.5	20%	30%	6.7	10.0	16.8
2.1.3	Hydro	100%	0%	360.8	360.8		360.8	20%	30%	72.2	108.2	180.4				0%	0%			
2.1.4	Lease Rentals	0%	100%	1,248.7		1,248.7		40%	60%				1,248.7		1,248.7	40%	60%	499.5	749.2	
2.1.5	Surface Rentals	0%	100%	0.0		0.0		40%	60%				0.0			40%	60%			
2.1.6	Provision for LUF	69%	31%	9,054.8	6,247.8	2,807.0	6,247.8	0%	0%			6,247.8	2,807.0	0.0	2,807.0	0%	0%			2,807.0
2.1	Subtotal			12,447.9	8,071.0	4,376.9	8,071.0			593.3	889.8	6,587.9	4,376.9	18.2	4,358.7			614.0	920.9	2,823.8
	MAINTENANCE																			
2.2.1	Company	90%	10%	1,798.1	1,618.3	179.8	1,618.3	10%	15%	161.8	242.7	1,213.8	179.8	10.2	169.6	10%	15%	17.0	25.4	127.2
2.2.2	Contractor	80%	20%	597.0	477.6	119.4	477.6	10%	15%	47.8	71.6	358.2	119.4	6.8	112.6	10%	15%	11.3	16.9	84.4
2.2	Subtotal			2,395.1	2,095.9	299.2	2,095.9			209.6	314.3	1,572.0	299.2	16.9	282.3			28.3	42.3	211.6
	ADMINISTRATIVE & GENERAL																			
2.3.1	General Office	80%	20%	1,975.4	1,580.3	395.1	1,580.3	40%	60%	632.1	948.2		395.1	22.3	372.8	40%	60%	149.1	223.7	
2.3.2	Service Fees	80%	20%	1,013.0	810.4	202.6	810.4	40%	60%	324.2	486.2		202.6	11.5	191.1	40%	60%	76.5	114.7	
2.3.3	Overhead Capitalized	80%	20%	(451.6)	(361.3)	(90.3)	(361.3)	40%	60%	(144.5)	(216.8)		(90.3)	0.0	(90.3)	40%	60%	(36.1)	(54.2)	
2.3	Subtotal			2,536.8	2,029.4	507.4	2,029.4			811.8	1,217.6		507.4	33.8	473.6			189.5	284.2	0.0
	DEPRECIATION AND AMORTIZATION																			
2.4.1	Depreciation	47%	53%	5,301.1	2,508.5	2,792.6	2,508.5	40%	60%	1,003.4	1,505.1		2,792.6	138.4	2,654.2	40%	60%	1,061.7	1,592.5	0.0
2.4.2	Amortization	0%	100%	868.3		868.3		40%	60%				868.3	0.0	868.3	40%	60%	347.3	521.0	0.0
2.4	Subtotal			6,169.4	2,508.5	3,660.9	2,508.5			1,003.4	1,505.1		3,660.9	138.4	3,522.5			1,409.0	2,113.5	
	TAXES - OTHER THAN INCOME																			
2.5.1	Municipal	80%	20%	1,351.0	1,080.8	270.2	1,080.8	40%	60%	432.3	648.5		270.2	15.3	254.9	40%	60%	102.0	152.9	
2.5.2	Capital Rate Base Ratio	40%	60%	505.0	202.0	303.0	202.0	40%	60%	80.8	121.2		303.0	17.1	285.9	40%	60%	114.3	171.5	
2.5	Subtotal			1,856.0	1,282.8	573.2	1,282.8			513.1	769.7		573.2	32.4	540.8			216.3	324.4	
2.	**TOTAL EXPENSES**			25,405.3	15,987.6	9,417.6	15,987.6			3,131.2	4,696.5	8,159.9	9,417.6	239.7	9,177.9			2,457.1	3,685.3	3,035.4
3.	**REVENUE REQUIREMENT**			41,315.2	22,351.5	18,963.6	22,351.5			5,676.8	8,514.9	8,159.9	18,963.6	239.7	18,723.8			6,275.5	9,412.9	3,035.4
4.1	**GROSS REVENUE REQUIREMENT (incl. fuel)**			41,315.2	22,351.5	18,963.6	22,351.5			5,676.8	8,514.9	8,159.9	18,963.6	239.7	18,723.8			6,275.5	9,412.9	3,035.4
4.2	**GROSS REVENUE REQUIREMENT (excl. fuel)**			41,315.2	22,351.5	18,963.6	22,351.5			5,676.8	8,514.9	8,159.9	18,963.6	239.7	18,723.8			6,275.5	9,412.9	3,035.4
3.1.1	Less: UNION GAS									321.1	508.0	477.1						0.0	0.0	0.0
3.1.2	Less: CENTRA GAS									56.2	50.8	83.4						65.8	59.7	33.0
3.1.1	Less: ST. LAWRENCE									0.0	0.0	0.0						0.0	0.0	0.0
3.1	**Net: CONSUMERS GAS**									5,299.5	7,956.1	7,599.4						6,209.7	9,353.2	3,002.4

TECUMSEH GAS
RATE DERIVATION
2007 TEST YEAR

Item No.	Transmission and Compression	Col.1 Annual Demand	Col.2 Daily Demand	Col.3 Commodity
1.1	Cost of service	5,676.8	8,514.9	8,159.9
1.2	Forecasted Gas Volumes	2,863,939.2	47,515.9	5,541,951.2
1.3.1	Unit Cost - Annual ($/$10^3m^3$)	1.982	179.201	1.472
1.3.2	Unit Cost - Monthly ($/$10^3m^3$/month)	0.165	14.933	0.000
1.3.3	Unit Cost - Rounded ($/$10^3m^3$)	0.165	14.933	1.472
1.4	Fuel Ratio (%)			0.35
	Pool Storage	**Annual Demand**	**Daily Demand**	**Commodity**
2.1	Cost of Service Analysis ($000's)	6,275.5	9,412.9	3,035.4
2.2	Forecasted Gas Volumes (10^3m^3)	2,701,939.2	44,680.9	5,217,951.2
2.3.1	Unit Cost - Annual ($/$10^3m^3$)	2.3226	210.6695	0.5817
2.3.2	Unit Cost - Monthly ($/$10^3m^3$/month)	0.1935	17.5558	0.0000
2.3.3	Unit Cost - Rounded ($/$10^3m^3$)	0.1935	17.5558	0.5817

Filed: 2007-02-23
Interim Rate Order
EB-2006-0034
Exhibit G2
Tab 7
Schedule 5

TECUMSEH GAS
ISOLATION OF TRANSMISSION RELATED RATE BASE
2007 TEST YEAR

($000)

				Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
				FUNCTIONALIZATION TOTAL COSTS			**ELIMINATION OF COMPRESSION COSTS**		**TRANSMISSION COSTS**	
Item No.	Description	Functional Allocation T/C	Pool	Net Investment Avg. of Mnthly Avg.	Transmission & Compression	Pool Storage Space	Compression	Pool Storage Space	Transmission	Pool Storage Space
1.1	Transmission Lines	100%	0%	9,519.5	9,519.5	0.0	0.0	0.0	9,519.5	0.0
1.2	Compressor Equipment	100%	0%	54,621.6	54,621.6	0.0	(43,693.9)	0.0	10,927.7	0.0
1.3	Structures & Improvements	100%	0%	7,414.0	7,414.0	0.0	(7,414.0)	0.0	0.0	0.0
1.4	Office and Plant Equipment	100%	0%	1,250.1	1,250.1	0.0	(1,186.4)	0.0	63.7	0.0
1.5	Land	100%	0%	188.7	188.7	0.0	(188.7)	0.0	0.0	0.0
1.6.1	Allowance for - Mat'ls & Supplies	100%	0%	2,362.3	2,362.3	0.0	(2,362.3)	0.0	0.0	0.0
1.6.2	- Working Cash Allow.	100%	0%	1,100.0	1,100.0	0.0	(1,072.3)	0.0	27.7	0.0
1.7	Provision for LUF	69%	31%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.				76,456.2	76,456.2	0.0	(55,917.6)	0.0	20,538.6	0.0
2.1	Field Lines	0%	100%	19,518.3	0.0	19,518.3	0.0	(19,518.3)	0.0	0.0
2.2	Wells	0%	100%	14,275.1	0.0	14,275.1	0.0	(14,275.1)	0.0	0.0
2.3	Well Equipment	0%	100%	3,638.6	0.0	3,638.6	0.0	(3,638.6)	0.0	0.0
2.4	Measuring & Regulating	0%	100%	8,472.1	0.0	8,472.1	0.0	(8,472.1)	0.0	0.0
2.5	Gas Storage Rights	0%	100%	22,708.2	0.0	22,708.2	0.0	(22,708.2)	0.0	0.0
2.6	Petroleum and Natural Gas Leases	0%	100%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.7	Base Pressure Gas	0%	100%	40,767.1	0.0	40,767.1	0.0	(40,767.1)	0.0	0.0
2.8	Other	0%	100%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.				109,379.4	0.0	109,379.4	0.0	(109,379.4)	0.0	0.0
3.	Total			185,835.6	76,456.2	109,379.4	(55,917.6)	(109,379.4)	20,538.6	0.0

TECUMSEH GAS
ISOLATION OF TRANSMISSION RELATED COST OF SERVICE
2007 TEST YEAR

		Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9
		TOTAL COST OF SERVICE					**ELIMINATION OF COMPRESSION COSTS**		**TRANSMISSION COSTS**	
Item No.		Functional Allocation T/C	Pool	Utility Return & Expenses	Transmission & Compression	Pool Storage	Compression	Pool Storage	Transmission	Pool Storage
	RATE BASE RETURN AMOUNT			($000)	($000)	($000)				
1.1	Utility Return (net of fuel)	40%	60%	15,909.9	6,364.0	9,545.9	(4,605.6)	(9,545.9)	1,758.4	0.0
1.	Total Return	0%	0%	15,909.9	6,364.0	9,545.9	(4,605.6)	(9,545.9)	1,758.4	0.0
	EXPENSES - OPERATION									
2.1.1	Labour	80%	20%	1,428.7	1,142.9	285.7	(1,142.9)	(285.7)	0.0	0.0
2.1.2	Supplies & Other	90%	10%	355.0	319.5	35.5	(319.5)	(35.5)	0.0	0.0
2.1.3	Compressor Station Fuel	100%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1.4	Compressor Station Fuel	100%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1.5	Other Fuel	100%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1.6	Other Fuel	100%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1.3	Hydro	100%	0%	360.8	360.8	0.0	(360.8)	0.0	0.0	0.0
2.1.4	Lease Rentals	0%	100%	1,248.7	0.0	1,248.7	0.0	(1,248.7)	0.0	0.0
2.1.5	Surface Rentals	0%	100%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1.6	Provision for LUF	69%	31%	9,054.8	6,247.8	2,807.0	(6,247.8)	(2,807.0)	0.0	0.0
2.1	Subtotal			12,447.9	8,071.0	4,376.9	(8,071.0)	(4,376.9)	0.0	0.0
	MAINTENANCE									
2.2.1	Company	90%	10%	1,798.1	1,618.3	179.8	(1,602.6)	(179.8)	15.8	0.0
2.2.2	Contractor	80%	20%	597.0	477.6	119.4	(445.6)	(119.4)	32.0	0.0
2.2	Subtotal			2,395.1	2,095.9	299.2	(2,048.2)	(299.2)	47.8	0.0
	ADMINISTRATIVE & GENERAL									
2.3.1	General Office	80%	20%	1,975.4	1,580.3	395.1	(1,556.9)	(395.1)	23.4	0.0
2.3.2	Service Fees	80%	20%	1,013.0	810.4	202.6	(808.6)	(202.6)	1.9	0.0
2.3.3	Overhead Capitalized	80%	20%	(451.6)	(361.3)	(90.3)		90.3	(49.9)	0.0
2.3	Subtotal			2,536.8	2,029.5	507.4	(2,365.5)	(507.4)	(24.7)	0.0
	DEPRECIATION AND AMORTIZATION									
2.4.1	Depreciation	47%	53%	5,301.1	2,508.5	2,792.6	(2,092.7)	(2,792.6)	415.8	0.0
2.4.2	Amortization	0%	100%	868.3	0.0	868.3	0.0	(868.3)	0.0	0.0
2.4	Subtotal			6,169.4	2,508.5	3,660.9	(2,092.7)	(3,660.9)	415.8	0.0
	TAXES - OTHER THAN INCOME									
2.5.1	Municipal	80%	20%	1,351.0	1,080.8	270.2	(780.8)	(270.2)	300.0	0.0
2.5.2	Capital	40%	60%	505.0	202.0	303.0	(146.2)	(303.0)	55.8	0.0
2.5	Subtotal			1,856.0	1,282.8	573.2	(927.0)	(573.2)	355.8	0.0
2.	**TOTAL EXPENSES**			25,405.3	15,987.7	9,417.6	(15,504.4)	(9,417.6)	794.7	0.0
3.	**REVENUE REQUIREMENT BEFORE TAXES**			41,315.2	22,351.7	18,963.5	(20,110.0)	(18,963.5)	2,553.1	0.0

FUNCTIONALIZATION OF SHORT CYCLE
NET REVENUES TO IN/EX FRANCHISE CUSTOMERS
2007 TEST YEAR
($000)

		Col. 1	Col. 2	Col. 3 (Col. 1*Col. 2)	Col. 4	Col. 5	Col. 6 (Col. 3*Col. 4)	Col. 7 (Col. 3*Col. 5)
Item No.	Description	Net Revenues ($000)	Sharing	Net Revenues Shared ($000)	T/C	Storage	T/C ($000)	Storage ($000)
1.	Short Cycle	4,368.0	100%	4,368.0	54%	46%	2,363.1	2,004.9

CLASSIFICATION AND ALLOCATION OF NET REVENUES TO IN/EX FRANCHISE CUSTOMERS

		Col. 1	Col. 2 (Col. 1*60%)	Col. 3 (Col 1*40%)	Col. 4	Col. 5	Col. 6 (Col. 4*Col. 2)	Col. 7 (Col. 5*Col. 3)	Col. 8 (Col. 6+Col. 7)
			NET REVENUES		VOLUMES		ALLOCATION		
Item No.	Description	Total ($000)	Daily ($000)	Annual ($000)	Daily	Annual	Daily ($000)	Annual ($000)	Total ($000)
	T/C								
1.1	In Franchise				100%	100%	1,417.9	945.2	2,363.1
1.2	Rate 325				0%	0%	0.0	0.0	0.0
1.3	Rate 330				0%	0%	0.0	0.0	0.0
1.4	Rate 331				0%	0%	0.0	0.0	0.0
1.	TOTAL	2,363.1	1,417.9	945.2	100%	100%	1,417.9	945.2	2,363.1
	Storage								
2.1	In Franchise				100%	100%	1,202.9	802.0	2,004.9
2.2	Rate 325				0%	0%	0.0	0.0	0.0
2.3	Rate 330				0%	0%	0.0	0.0	0.0
2.4	Rate 331				0%	0%	0.0	0.0	0.0
2.	TOTAL	2,004.9	1,202.9	802.0	100%	100%	1,202.9	802.0	2,004.9
	Total T/C and Storage								
3.1	In Franchise						2,620.8	1,747.2	4,368.0
3.2	Rate 325						0.0	0.0	0.0
3.3	Rate 330						0.0	0.0	0.0
3.4	Rate 331						0.0	0.0	0.0
3.	TOTAL	4,368.0	2,620.8	1,747.2			2,620.8	1,747.2	4,368.0

APPENDIX "C"

TO INTERIM RATE ORDER

BOARD FILE NO. EB-2006-0034

DATED MARCH 26, 2007

RIDER: E	REVENUE ADJUSTMENT RIDER

The following adjustment shall be applicable to billed volumes during the period April 1, 2007 to December 31, 2007.

Rate Class	Sales Service (¢/m³)	Transportation Service (¢/m³)
Rate 1	0.2688	0.2310
Rate 6	0.0798	0.0185
Rate 9	0.2598	0.2586
Rate 100	(0.1788)	(0.1732)
Rate 110	(0.0327)	(0.0346)
Rate 115	0.0132	0.0117
Rate 135	0.0038	0.0038
Rate 145	(0.1556)	(0.1402)
Rate 170	0.0174	0.0153
Rate 200	0.1244	0.1204
Rate 300	0.0000	(0.0640)

APPENDIX “D”

TO INTERIM RATE ORDER

BOARD FILE NO. EB-2006-0034

DATED MARCH 26, 2007

RATE HANDBOOK

ENBRIDGE GAS DISTRIBUTION

HANDBOOK OF RATES AND DISTRIBUTION SERVICES

INDEX

Part I

GLOSSARY OF TERMS

In this Handbook of Rates and Distribution Services, each term set out below shall have the meaning set out opposite it:

Annual Turnover Volume ("ATV"): The sum of the contracted volumes injected into and withdrawn from storage by an applicant within a contract year.

Annual Volume Deficiency: The difference between the Minimum Annual Volume and the volume actually taken in a contract year, if such volume is less than the Minimum Annual Volume.

Applicant: The party who makes application to the Company for one or more of the services of the Company and such term includes any party receiving one or more of the services of the Company.

Authorized Volume: In regards to Sales Service Agreements, the Contract Demand.

In regards to Bundled Transportation Service arrangements, the Contract Demand (CD) less the amount by which the Applicant's Mean Daily Volume (MDV) exceeds the Daily Delivered Volume (Delivery) and less the volume by which the Applicant has been ordered to curtail or discontinue the use of gas (Curtailment Volume) or otherwise represented as:

CD – (MDV – Delivery) – Curtailment Volume

Back-stopping: A service whereby alternative supplies of gas may be available in the event that an Applicant's supply of gas is not available for delivery to the Company.

Banked Gas Account: A record of the amount of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of volume of gas taken by the Applicant at the Terminal Location (debits)

Billing Contract Demand: Applicable only to new customers who take Dedicated Service under Rate 125. The Company and the Applicant shall determine a Billing Contract Demand which would result in annual revenues over the term of the contract that would enable the Company to recover the invested capital, return on capital, and O&M costs of the Dedicated Service in accordance with its system expansion policies.

Billing Month: A period of approximately thirty (30) days following which the Company renders a bill to an applicant. The billing month is determined by the Company's monthly Reading and Billing Schedule. With respect to rate 135 LVDC's, there are eight summer months and four winter months.

Board: Ontario Energy Board. (OEB)

Bundled Service: A service in which the demand for natural gas at a Terminal Location is met by the Company utilizing Load balancing resources.

Buy/Sell Arrangement: An arrangement, the terms of which are provided for in one or more agreements to which one or more of an end user of gas (being a party that buys from the Company gas delivered to a Terminal Location), an affiliate of an end user and a marketer, broker or agent of an end user is a party and the Company is a party, and pursuant to which the Company agrees to buy from the end user or its affiliate a supply of gas and to sell to the end user gas delivered to a Terminal Location served from the gas distribution network. The Company will not enter into any new buy/sell agreement after April 1, 1999.

Buy/Sell Price: The Price per cubic meter which the Company would pay for gas purchased pursuant to a Buy/Sell Arrangement in which the purchase takes place in Ontario.

Commodity Charge: A charge per unit volume of gas actually taken by the Applicant, as distinguished from a demand charge which is based on the maximum daily volume an Applicant has the right to take.

Company: Enbridge Gas Distribution Inc.

Contract Demand: A contractually specified volume of gas applicable to service under a particular Rate Schedule for each Terminal Location which is the maximum volume of gas the Company is required to deliver on a daily basis under a Large Volume Distribution Contract.

Cubic Metre ("m^3"): That volume of gas which at a temperature of 15 degrees Celsius and at an absolute pressure of 101.325 kilopascals ("kPa") occupies one cubic metre. "10^3m^3" means 1,000 cubic metres.

Curtailment: An interruption in an Applicant's gas supply at a Terminal Location resulting from compliance with a request or an order by the Company to discontinue or curtail the use of gas.

Curtailment Credit: A credit available to interruptible customers to recognize the benefits they provide to the system during the winter months.

Curtailment Delivered Supply (CDS): An additional volume of gas, in excess of the Applicant's Mean Daily Volume and determined by mutual agreement between the Applicant and the Company, which is Nominated and delivered by or on behalf of the Applicant to a point of interconnection with the Company's distribution system on a day of Curtailment.

Customer Charge: A monthly fixed charge that reflects being connected to the gas distribution system.

Daily Consumption VS Gas Quantity: The volume of natural gas taken on a day at a Terminal Location as measured by daily metering equipment or, where the Company does not own and maintain daily metering equipment at a Terminal Location, the volume of gas taken within a billing period divided by the number of days in the billing period.

Daily Delivered Volume: The volume of gas accepted by the Company as having been delivered by an Applicant to the Company on a day.

Dedicated Service: An Unbundled Service provided through a gas distribution pipeline that is initially constructed to serve a single customer, and for which the volume of gas is measured through a billing meter that is directly connected to a third party transporter or other third party facility, when service commences.

Delivery Charge: A component of the Rate Schedule through which the Company recovers its operating costs.

Demand Charge: A fixed monthly charge which is applied to the Contract Demand specified in a Service Contract.

Demand Overrun: The amount of gas taken at a Terminal Location exceeding the Contract Demand.

Direct Purchase: Natural gas supply purchase arrangements transacted directly between the Applicant and one or more parties, including the Company.

Disconnect and Reconnect Charges: The charges levied by the Company for disconnecting or reconnecting an Applicant from or to the Company's distribution system.

Diversion: Delivery of gas on a day to a delivery point different from the normal delivery point specified in a Service Contract.

Firm Service: A service for a continuous delivery of gas without curtailment, except under extraordinary circumstances.

Firm Transportation ("FT"): Firm Transportation service offered by upstream pipelines to move gas from a receipt point to a delivery point, as defined by the pipeline.

Force Majeure: A contract clause intended to excuse one or more parties from their obligations under a contract, in situations where performance is frustrated by unusual or severe circumstances beyond their control such as flood, fire, war, or prolonged labour strike.

Gas: Natural Gas.

Gas Delivery Agreement: A written agreement pursuant to which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.

Gas Distribution Network: The physical facilities owned by the Company and utilized to contain, move and measure natural gas.

Gas Sale Contract: A written agreement pursuant to which the Company agrees to supply and deliver gas to a specified Terminal Location.

Gas Supply Charge: A charge for the gas commodity purchased by the applicant.

Gas Supply Load Balancing Charge: A charge in the Rate Schedules where the Company recovers the cost of ensuring gas supply matches consumption on a daily basis.

General Service Rates: The Rate Schedules applicable to those Bundled Services for which a specific contract between the Company and the Applicant is not generally required. The General Service Rates include Rates 1, 6, and 9 of the Company.

Gigajoule ("GJ"): See Joule.

Hourly Demand: A contractually specified volume of gas applicable to service under a particular Rate Schedule which is the maximum volume of gas the Company is required to deliver to an Applicant on a hourly basis under a Service Contract.

Imperial Conversion Factors:

Volume:		
1,000 cubic feet (cf)	=	1 Mcf
	=	28.32784 cubic metres (m^3)
1 billion cubic feet (cf)	=	28.32784 $10^6 m^3$
Pressure:		
1 pound force per square inch (p.s.i.)	=	6.894757 kilopascals (kPa)
1 inch Water Column (in W.C.) (60°F)	=	0.249 kPa (15.5°C)
1 standard atmosphere	=	101.325 kPa
Energy:		
1 million British thermal units	=	1 MMBtu
	=	1.055056 gigajoules (GJ)
948,213.3 Btu	=	1 GJ
Monetary Value:		
$1 per Mcf	=	$0.03530096 per m^3
$1 per MMBtu	=	$0.9482133 per GJ

Interruptible Service: Gas service which is subject to curtailment for either capacity and/or supply reasons, at the option of the Company.

Intra-Alberta Service: Firm transportation service on the Nova pipeline system under which volumes are delivered to an Intra-Alberta point of acceptance.

Joule ("J"): The amount of work done when the point of application of a force of one newton is displaced a distance of one metre in the direction of the force. One megajoule ("MJ") means 1,000,000 joules; one gigajoule ("GJ") means 1,000,000,000 joules.

Large Volume Distribution Contract: (LVDC): A written agreement pursuant to which the Company agrees to supply and deliver gas to a specified Terminal Location.

Large Volume Distribution Contract Rates: The Rate Schedules applicable for annual consumption exceeding 340,000 cubic metres of gas per year and for which a specific contract between the Company and the Applicant is required.

Load-Balancing: The balancing of the gas supply to meet demand. Storage and other peak supply sources, curtailment of interruptible services, and diversions from one delivery point to another may be used by the Company.

Make-up Volume: A volume of gas nominated and delivered, pursuant to mutually agreed arrangements, by an Applicant to the Company for the purpose of reducing or eliminating a net debit balance in the Applicant's Banked Gas Account.

Mean Daily Volume (MDV): The volume of gas which an Applicant who delivers gas to the Company, under a T-Service arrangement, agrees to deliver to the Company each day in the term of the arrangement.

Metric Conversion Factors:

Volume:

1 cubic metre (m^3)	=	35.30096 cubic feet (cf)
1,000 cubic metres	=	10^3m^3
	=	35,300.96 cf
	=	35.30096 Mcf
28.32784 m^3	=	1 Mcf

Pressure:

1 kilopascal (kPa)	=	1,000 pascals
	=	0.145 pounds per square inch (p.s.i.)
101.325 kPa	=	one standard atmosphere

Energy:

1 megajoule (MJ)	=	1,000,000 joules
	=	948.2133 British thermal units (Btu)
1 gigajoule (GJ)	=	948,213.3 Btu
1.055056 GJ	=	1 MMBtu

Monetary Value:

$1 per 10^3m^3	=	$0.02832784 per Mcf
$1 per gigajoule	=	$1.055056 per MMBtu

Minimum Annual Volume: The minimum annual volume as stated in the customer's contract, also Section E.

Natural Gas: Natural and/or residue gas comprised primarily of methane.

Nominated Volume: The volume of gas which an Applicant has advised the Company it will deliver to the Company in a day.

Nominate, Nomination: The procedure of advising the Company of the volume which the Applicant expects to deliver to the Company in a day.

Ontario Energy Board: An agency of the Ontario Government which, amongst other things, approves the Company's Rate Schedules (Part V of this HANDBOOK) and the matters described in Parts III and IV of this HANDBOOK.

Point of Acceptance: The point at which the Company accepts delivery of a supply of natural gas for transportation to, or purchase from, the Applicant.

Rate Schedule: A numbered rate of the Company as fixed or approved by the OEB. that specifies rates, applicability, character of service, terms and conditions of service and the effective date.

Seasonal Credit: A credit applicable to Rate 135 customers to recognize the benefits they provide to the storage operations during the winter period.

Service Contract: An agreement between the Company and the Applicant which describes the responsibilities of each party in respect to the arrangements for the Company to provide Sales Service or Transportation Service to one or more Terminal Locations.

System Sales Service: A service of the Company in which the Company acquires and sells to the Applicant the Applicant's natural gas requirements.

T-Service: Transportation Service.

Terminal Location: The building or other facility of the Applicant at or in which natural gas will be used by the Applicant.

Transportation Service: A service in which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.

Unbundled Service: A service in which the demand for natural gas at a Terminal Location is met by the Applicant contracting for separate services (upstream transportation, load balancing/storage, transportation on the Company's distribution system) of which only Transportation Service is mandatory with the Company.

Western Canada Buy Price: The price per cubic metre which the Company would pay for gas pursuant to a Buy/Sell Agreement in which the purchase takes place in Western Canada.

PART II

RATES AND SERVICES AVAILABLE

The provisions of this PART II are intended to provide a general description of services offered by the Company and certain matters relating thereto. Such provisions are not definitive or comprehensive as to their subject matter and may be changed by the Company at any time without notice.

SECTION A - INTRODUCTION

1. In Franchise Services

Enbridge Gas Distribution provides in franchise services for the transportation of natural gas from the point of its delivery to Enbridge Gas Distribution to the Terminal Location at which the gas will be used. The natural gas to be transported may be owned by the Applicant for service or by the Company. In the latter case, it will be sold to the customer at the outlet of the meter located at the Terminal Location.

Applicants may elect to have the Company provide all-inclusively the services which are mutually agreed to be required or they may select (from the 300 series of rates, and Rate 125) only the amounts of those services which they consider they need.

The all-inclusive services are provided pursuant to Rates 1, 6 and 9, ("the General Service Rates") and Rates 100, 110, 115, 135, 145, and 170 ("the Large Volume Service Rates"). Individual services are available under Rates 125, 300, and 315 ("the Unbundled Service Rates").

Service to residential locations is provided pursuant to Rate 1.

Service which may be interrupted at the option of the Company is available, at rates lower than would apply for equivalent service under a firm rate schedule, pursuant to Rates 145, 170. Under all other rate schedules, service is provided upon demand by the Applicant, i.e., on a firm service basis.

2. Ex-Franchise Services

Enbridge Gas Distribution provides ex-franchise services for the transportation of natural gas through its distribution system to a point of interconnection with the distribution system of other distributors of natural gas. Such service is provided pursuant to Rate 200 and provides for the bundled transportation of gas owned by the Company, owned by customers of that distributor, or owned by that distributor.

For the purposes of interpreting the terms and conditions contained in this Handbook of Rates and Distribution Services the ex - franchise distributor shall be considered to be the applicant for the transportation of its customer owned gas and shall assume all the obligations of transportation as if it owned the gas.

Nominations for transportation service must specify whether the volume to be transported is to displace firm or interruptible demand or general service.

In addition, the Company provides Compression, Storage, and Transmission services on its Tecumseh system under Rates 325, 330 and 331.

SECTION B - DIRECT PURCHASE ARRANGEMENTS

Applicants who purchase their natural gas requirements directly from someone other than the Company or who are brokers or agents for an end user, may arrange to transport gas on the Company's distribution network in conjunction with a Western Buy/Sell Arrangement or pursuant to an Ontario Delivery Transportation Service Arrangement, whether Bundled or Unbundled, or a Western Bundled Transportation Service Arrangement.

B. Western Canada Buy/Sell in a Western Canada Buy/Sell Arrangement the Applicant delivers gas to a point in Western Canada which connects with the transmission pipeline of TransCanada PipeLines Limited. At that point, the Company purchases the gas from the Applicant at a price specified in Rider 'B' of the rate schedules less the costs for transmission of the gas from the point of purchase to a point in Ontario at which the Company's gas distribution network connects with a transmission pipeline system. The Company will not be entering into any new Western Canada buy/sell arrangements after April 1, 1999.

C. Ontario Delivery T-Service Arrangements

In an Ontario Delivery T-Service Arrangement the Applicant delivers gas, to a contractually agreed-upon point of acceptance in Ontario.

Delivery from the point of direct interconnection with the Company's gas distribution network to a Terminal Location served from the Company's gas distribution network may be obtained by the Applicant either under the Bundled Service Rate Schedules or under the Unbundled Service Rate Schedules.

(i) Bundled T-Service

Bundled T-Service is so called because all of the services required by the Applicant (delivery and load balancing) are provided for the prices specified in the applicable Rate Schedule. In a Bundled T-Service arrangement the Applicant contracts to deliver each day to the Company a Mean Daily Volume of gas. Fluctuations in the demand for gas at the Terminal Location are balanced by the Company.

(ii) Unbundled T-Service

The Unbundled Service Rates allow an Applicant to contract for only such kinds of service as the Applicant chooses. The potential advantage to an Applicant is that the chosen amounts of service may be less than the amounts required by an average customer represented in the applicable Rate Schedule, in which case the Applicant may be able to reduce the costs otherwise payable under Bundled T-Service.

D. Western Delivery T-Service Arrangement

In a Western Delivery T-Service Arrangement the Applicant contracts to deliver each day to a point on the TransCanada PipeLines Ltd. transmission system in Western Canada a Mean Daily Volume of gas plus fuel gas. Delivery from that point to the Terminal Location is carried out by the Company using its contracted capacity on the TransCanada PipeLines Limited. system and its gas distribution network. Unbundled T-Service in Ontario is not available with the Western Delivery Option.

An Applicant desiring to receive Transportation Service or to establish a Buy/Sell Agreement must first enter into the applicable written agreements with the Company.

PART III

TERMS AND CONDITIONS APPLICABLE TO ALL SERVICES

The provisions of this PART III are applicable to, and only to, Sales Service and Transportation Service.

SECTION A - AVAILABILITY

Unless otherwise stated in a Rate Schedule, the Company's rates and services are available throughout the entire franchised area serviced by the Company. Transportation service and/or sales service will be provided subject to the Company having the capacity in its gas distribution network to provide the service requested. When the Company is requested to supply the natural gas to be delivered, service shall be available subject to the Company having available to it a supply of gas adequate to meet the requirement without jeopardizing the supply to its existing customers.

Service shall be made available after acceptance by the Company of an application for service to a Terminal Location at which the natural gas will be used.

SECTION B - ENERGY CONTENT

The price of natural gas sold at a Terminal Location is based on the assumption that each cubic metre of such natural gas contains a certain number of megajoules of energy which number is specified in the Rate Schedules. Variations in cost resulting from the energy content of the gas actually delivered to the Company by its supplier(s) differing from the assumed energy content will be recorded and used to adjust future bills. Such adjustments shall be made in accordance with practices approved from time to time by the Ontario Energy Board.

SECTION C - SUBSTITUTION PROVISION

The Company may deliver gas from any standby equipment provided that the gas so delivered shall be reasonably equivalent to the natural gas normally delivered.

SECTION D - BILLS

Bills will be mailed or delivered monthly or at such other time period as set out in the Service Contract. Gas consumption to which the Company's rates apply will be determined by the Company either by meter reading or by the Company's estimate of consumption where meter reading has not occurred. The rates and charges applicable to a billing month shall be those applicable to the calendar month which includes the last day of the billing month.

SECTION E - MINIMUM BILLS

The minimum bill per month applicable to service under any particular Rate Schedule shall be the Customer Charge plus any applicable Contract Demand Charges for Delivery, Gas Supply Load Balancing, and Gas Supply and any applicable Direct Purchase Administration Charge, all as provided for in the applicable Rate Schedule.

In addition, for service under each of the Large Volume Distribution Contact Rates, if in a contract year a volume of gas equal to or greater than the product of the Contract Demand multiplied by a contractually specified multiple of the Contract Demand ("Minimum Annual Volume") is not taken at the Terminal Location the Applicant shall pay, in addition to the minimum monthly bills, the amount obtained when the difference between the Minimum Annual Volume and the volume taken in the contract year (such difference being the Annual Volume Deficiency) is multiplied by the applicable Minimum Bill Charge(s) as provided for in the applicable Rate Schedule. Notwithstanding the foregoing, the Minimum Annual Volume shall be the greater of the Minimum Annual Volume as determined above and 340,000 m^3.

If gas deliveries to the Terminal Location have been ordered to be curtailed or discontinued in a contract year at the request of the Company and have been curtailed or discontinued as ordered, the Minimum Annual Volume shall be reduced for each day of curtailment or discontinuance by the excess of the Contract Demand over the volume delivered to the Terminal Location on such day.

SECTION F - PAYMENT CONDITIONS

Enbridge Gas Distribution charges are due when the bill is received, which is considered to be three days after the date the bill is rendered, or within such other time period as set out in the Service Contract. A late payment charge of 1.5% of all of the unpaid Enbridge Gas Distribution charges, including all applicable federal and provincial taxes, is applied to the account on the seventeenth (17^{th}) day following the date the bill is due.

SECTION G - TERM OF ARRANGEMENT

When gas service is provided and there is no written agreement in effect relating to the provision of such service, the term for which such service is to continue shall be one year. The term shall automatically be extended for a further year immediately following the expiry of any initial one year term or one year extension unless reasonable notice to terminate service is given to the Company, in a manner acceptable to the Company, prior to the expiry of the term. An Applicant receiving such service who temporarily discontinues service in the initial one year term or any one year extension and does not pay all the minimum bills for the period of such temporary discontinuance of service shall, upon the continuance of service, be liable to pay an amount equal to the unpaid minimum bills for such period. When a written agreement is in effect relating to the provision of gas service, the term for which such service is to continue shall be as provided for in the agreement.

SECTION H - RESALE PROHIBITION

Gas taken at a Terminal Location shall not be resold other than in accordance with all applicable laws and regulations and orders of any governmental authority or OEB having jurisdiction.

SECTION I - MEASUREMENT

The Company will install, operate and maintain at a Terminal Location such measurement equipment of suitable capacity and design as is required to measure the volume of gas delivered. Any special conditions for measurement are contained in the General Terms and Conditions which form part of each Large Volume Distribution Contract.

SECTION J - RATES IN CONTRACTS

Notwithstanding any rates for service specified in any Service Contract, the rates and charges provided for in an applicable Rate Schedule shall apply for service rendered on and after the effective date stated in such Rate Schedule until such Rate Schedule ceases to be applicable.

SECTION K - ADVICE RE: CURTAILMENT

The Company, if requested, will advise Applicants taking interruptible service of its estimate of service curtailment for the forthcoming winter. Such estimate will be provided as guidance to the Applicant in arranging for alternate fuel supply requirements. Abnormal weather and/or other unforeseen events may cause greater or lesser curtailment of service than expected.

SECTION L - DAILY DELIVERED VOLUMES

For purposes including that of calculating daily overrun gas volumes, the Company will recognize as having been delivered to it on a given day the sum of:

a) the volume of gas delivered under Intra-Alberta transportation arrangements, if any, plus;

b) the volume of gas delivered under FT transportation arrangements, if any, plus;

SECTION M - AUTHORIZED OVERRUN GAS

If an Applicant requests permission to exceed the Authorized Volume for a day, and such authorization is granted, such gas shall constitute Authorized Overrun Gas. Such gas shall either be sold by the Company to the Applicant pursuant to the provisions of Rate 320 applicable on such day, or, at the Company's sole discretion, under the Rate Schedule the customer is purchasing prior to such request. If the Applicant is supplying their own gas requirements and if the Applicant request and at the Company's sole discretion, such Overrun Gas will be debited to the Applicant's Baked gas Account.

SECTION N - UNAUTHORIZED SUPPLY OVERRUN GAS

If an Applicant for Transportation Service pursuant to the General Service Rates on any day delivers to the Company a Daily Delivered Volume less than the Mean Daily Volume, the volume of gas by which the Mean Daily Volume applicable to such day exceeds the Daily Delivered Volume delivered by the Applicant to the Company on such day shall constitute Unauthorized Supply Overrun Gas and shall be deemed to have been taken and purchased on such day. The rate applicable to such volume shall be 150% of the average price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and the EDA delivery areas respectively.

Unauthorized Supply Overrun Gas for a day applicable to a Service Contract with an Applicant for service under the Large Volume Distribution Contract Rates is:

(a) the volume of gas by which the Daily Gas Quantity under the Service Contract on such day exceeds the Authorized Volume for such day, if any

plus

(b) if the day is in the months of December to March inclusive for an Applicant taking service on Rate 135, or if the day is a day on or in respect of which the Applicant has been requested in accordance with the Service Contract to curtail or discontinue the use of gas and the Service Contract is in whole or in part for interruptible Transportation Service, the volume of gas, if any, by which

(i) the Mean Daily Volume set out in the Service Contract and is applicable to such day exceeds

(ii) the Daily Delivered Volume delivered by the Applicant to the Company on such day, which excess volume of gas shall be deemed to have been taken and purchased by the Applicant on such day.

The Applicant shall pay the Company for Unauthorized Supply Overrun Gas at the rate applicable to Unauthorized Supply Overrun Gas as provided for in the Rate Schedule(s) applicable to the Service Contract.

Unauthorized Supply Overrun Gas for a day applicable to a Service Contract with an Applicant for service under Rate 125 or Rate 300 shall be determined from the provisions of the applicable Rate Schedule. The Applicant shall pay the Company for Unauthorized Supply Overrun Gas at the rate applicable to Unauthorized Supply Overrun Gas as provided for in the Rate Schedule(s) applicable to the Service Contract.

PART IV

TERMS AND CONDITIONS – DIRECT PURCHASE ARRANGEMENTS

Any Applicant, at the time of applying for service, may elect, in and for the term of any Service Contract, to deliver its own natural gas requirements to the Company and the Company shall deliver gas to a Terminal Location as required by the Applicant, subject to the terms and conditions contained in the applicable Rate Schedule and in the Service Contract. For Buy/Sell Arrangements and Bundled T-Service the deliveries by the Applicant to the Company shall be at the Applicant's estimated mean daily rate of consumption.

Backstopping of an Applicant's natural gas supply for Transportation Service arrangements will be available pursuant to Rate 320 subject to the Company's ability to do so using reasonable commercial efforts. Gas Purchase Agreements in respect to Buy/Sell Arrangements shall specify terms and conditions available to the Company to alleviate certain consequences of the Applicant's failure to deliver the required volume of gas.

The following Terms and Conditions shall apply to, and only to, Transportation Service and/or Gas Purchase Agreements.

SECTION A - NOMINATIONS

An Applicant delivering gas to the Company pursuant to a contract is responsible for advising the Company, by means of a contractually specified Nomination procedure, of the daily volume of gas to be delivered to the Company by or on behalf of the Applicant.

An initial daily volume must be Nominated by a contractually specified time before the first day on which gas is to be delivered to the Company. Any Nomination, once accepted by the Company, shall be considered as a standing nomination applicable to each subsequent day in a contract term unless specifically varied by written notice to the Company.

A contract may specify certain contractual provisions that are applicable in the event that an Applicant either fails to advise of a revised daily nomination or fails to deliver the daily volume so nominated.

A Nominated Volume in excess of the Applicant's Maximum Daily Volume as specified in the Service Contract will not be accepted except as specifically provided for in any contract.

SECTION B - OBLIGATION TO DELIVER

During any period of curtailment or discontinuance of Bundled interruptible Transportation Service as ordered by the Company, any Applicant supplying its own gas requirements must, on such day, deliver to the Company the Mean Daily Volume of gas specified in any Service Contract.

An Applicant taking service on Rate 135 must deliver to the Company the Mean Daily Volume of gas specified in the Service Contract in the months of December to March, inclusive.

Applicants taking service on General Service rates pursuant to a Direct Purchase Agreement must, on each day in the term of such agreement, deliver to the Company the Mean Daily Volume of gas specified in such agreement.

SECTION C - DIVERSION RIGHTS

Subject to compliance with the Terms and Conditions of all Required Orders, an Applicant who has entered into a Transportation Service Agreement or Agreements which provide(s) for deliveries to the Company for more than one Terminal Location shall have the right, on such terms and only on such terms as are specified in the applicable Transportation Service Agreement, to divert deliveries from one or more contractually specified Terminal Locations to other contractually specified Terminal Locations.

SECTION D - BANKED GAS ACCOUNT

For T-Service Applicants, the Company shall keep a record ("Banked Gas Account") of the volume of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of the volume of gas taken by the Applicant at the Terminal Location (debits). (Any volume of gas sold by the Company to the Applicant in respect to the Terminal Location shall not be debited to the Banked Gas Account). The Company shall periodically report to the Applicant the net balance in the Applicant's Banked Gas Account.

SECTION E - DISPOSITION OF BANKED GAS ACCOUNT BALANCES

A. The following Terms and Conditions shall apply to Bundled T-Service:

(a) At the end of each contract year, disposition of any net debit balance in the Banked Gas Account shall be made as follows:

The Applicant, by written notice to the Company within thirty (30) days of the end of the contract year, may elect to return to the Company, in kind, during the one hundred and eighty (180) days following the end of the contract year that portion of any debit balance in the Banked Gas Account as at the end of the contract year not exceeding a volume of twenty times the Applicant's Mean Daily Volume by the Applicant delivering to the Company on days agreed upon by the Company and the Applicant a volume of gas greater than the Mean Daily Volume, if any, applicable to such day under a Service Contract. Any volume of gas returned to the Company as aforesaid shall not be credited to the Banked Gas Account in the subsequent contract year. Any debit balance in the Banked Gas Account as at the end of the contract year which is not both elected to be returned, and actually returned, to the Company as aforesaid shall be deemed to have been sold to the Applicant and the Applicant shall pay for such gas within ten (10) days of the rendering of a bill therefor. The rate applicable to such gas shall be 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

(b)A credit balance in the Banked Gas Account as at the end of the contract year must be eliminated in one or more of the following manners, namely:

(i) Subject to clause (ii), if the Applicant continues to take service from the Company under a contract pursuant to which the Applicant delivers gas to the Company and the Applicant so elects (by written notice to the Company within thirty (30) days of the end of the contract year), that portion of such balance which the Applicant stipulates in such written notice and which does not exceed twenty times the Applicant's Mean Daily Volume may be carried forward as a credit to the Banked Gas Account for the next succeeding contract year. Any volume duly elected to be carried forward under this clause shall, and may only, be reduced within the period of one hundred and eighty (180) days ("Adjustment Period") immediately following the contract year, by the Applicant delivering to the Company, on days in the Adjustment Period agreed upon by the Company and the Applicant ("Adjustment Days"), a volume of gas less than the Mean Daily Volume applicable to such day under a Service Contract. Subject to the foregoing, the credit balance in the Banked Gas Account shall be deemed to be reduced on each Adjustment Day by the volume ("Daily Reduction Volume") by which the Mean Daily Volume applicable to such day exceeds the greater of the volume of gas delivered by the Applicant on such day and the Nominated Volume for such day which was accepted by the Company.

(ii) Any portion of a credit balance in the Banked Gas Account which is not eligible to be eliminated in accordance with clause (i), or which the Applicant elects (by written notice to the Company within thirty (30) days of the end of the contract year) to sell under this clause, shall be deemed to have been tendered for sale to the Company and the Company shall purchase such portion at a price per cubic metre of eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, less the average Ontario Transportation Service Credit over the contract year. Any volume of gas deemed to have been so tendered for sale shall be deemed to have been eliminated from the credit balance of the Banked Gas Account.

During the Adjustment Period the Company shall use reasonable efforts to accept the Applicant's reduced gas deliveries. Any credit balance in the Banked Gas Account not eliminated as aforesaid in the Adjustment Period shall be forfeited to, and be the property of, the Company, and such volume of gas shall be debited to the Banked Gas Account as at the end of the Adjustment Period.

Subject to its ability to do so, the Company will attempt to accommodate arrangements which would permit adjustments to Banked Gas Account balances at times and in a manner which are mutually agreed upon by the Applicant and the Company.

B. The following Terms and Conditions shall apply to Unbundled T-Service:

The Terms and Conditions for disposition of Banked Gas Account balances shall be as specified in the applicable Service Contracts.

RATE NUMBER: 1	RESIDENTIAL SERVICE

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a residential building served through one meter and containing no more than six dwelling units ("Terminal Location").

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$11.88**
Delivery Charge per cubic metre	
For the first 30 m³ per month	**14.8804 ¢/m³**
For the next 55 m³ per month	**14.2171 ¢/m³**
For the next 85 m³ per month	**13.6973 ¢/m³**
For all over 170 m³ per month	**13.3103 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**34.1108 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider “F”.
The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

RATE NUMBER: 6	GENERAL SERVICE

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location ("Terminal Location") for non-residential purposes.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$23.58**
Delivery Charge per cubic metre	
For the first 500 m³ per month	**13.9886 ¢/m³**
For the next 1050 m³ per month	**11.7886 ¢/m³**
For the next 4500 m³ per month	**10.2485 ¢/m³**
For the next 7000 m³ per month	**9.2586 ¢/m³**
For the next 15250 m³ per month	**8.8185 ¢/m³**
For all over 28300 m³ per month	**8.7085 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**34.2738 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider “F”.
The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location ("Terminal Location") at which, such gas is authorized by the Company to be resold by filling pressurized containers.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$220.55**
Delivery Charge per cubic metre	
For the first 20,000 m³ per month	**13.6756 ¢/m³**
For all over 20,000 m³ per month	**13.0346 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.9398 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of a specified annual volume of natural gas of not less than 340,000 cubic metres to be delivered at a specified maximum daily rate.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$115.10**
Delivery Charge	
Per cubic metre of Contract Demand	**8.0000 ¢/m³**
For the first 14,000 m³ per month	**4.8245 ¢/m³**
For the next 28,000 m³ per month	**3.4655 ¢/m³**
For all over 42,000 m³ per month	**2.9065 ¢/m³**
Gas Supply Load Balancing Charge	**4.3285 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.9953 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the average price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

9.0554 ¢/m³

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

RATE NUMBER: **110**	**LARGE VOLUME LOAD FACTOR SERVICE**

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 183 times a specified maximum daily volume of not less than 1,865 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month
	January to December
Monthly Customer Charge	**$554.50**
Delivery Charge	
Per cubic metre of Contract Demand	**22.1800 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.5044 ¢/m³**
For all over 1,000,000 m³ per month	**0.3544 ¢/m³**
Gas Supply Load Balancing Charge	**3.8370 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.9398 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the average price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

4.2438 ¢/m³

In determining the Annual Volume Deficiency, the minimum bill multiplier shall not be less than 183.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

RATE NUMBER: **115**	**LARGE VOLUME LOAD FACTOR SERVICE**

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 292 times a specified maximum daily volume of not less than 1,165 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$610.78**
Delivery Charge	
Per cubic metre of Contract Demand	**24.4300 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.2730 ¢/m³**
For all over 1,000,000 m³ per month	**0.1730 ¢/m³**
Gas Supply Load Balancing Charge	**3.0382 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.9398 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the average price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

RATE NUMBER: **115**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

3.2136 ¢/m³

In determining the Annual Volume Deficiency the minimum bill multiplier shall not be less than 292.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

RATE NUMBER: **125**	**EXTRA LARGE FIRM DISTRIBUTION SERVICE**

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of a specified maximum daily volume of natural gas. The maximum daily volume for billing purposes, Contract Demand or Billing Contract Demand, as applicable, shall not be less than 600,000 cubic metres. The Service under this rate requires Automatic Meter Reading (AMR) capability.

CHARACTER OF SERVICE:

Service shall be firm except for events specified in the Service Contract including force majeure.

For Non-Dedicated Service the monthly demand charges payable shall be based on the Contract Demand which shall be 24 times the Hourly Demand and the Applicant shall not exceed the Hourly Demand.

For Dedicated Service the monthly demand charges payable shall be based on the Billing Contract Demand specified in the Service Contract. The Applicant shall not exceed an hourly flow calculated as 1/24th of the Contract Demand specified in the Service Contract.

DISTRIBUTION RATES:

The following rates and charges, as applicable, shall apply for deliveries to the Terminal Location.

Monthly Customer Charge	**$500.00**
Demand Charge	
Per cubic metre of the Contract Demand or the Billing Contract Demand, as applicable, per month	**8.9017 ¢/m³**
Direct Purchase Administration Charge	**$50.00**
Forecast Unaccounted For Gas Percentage	**0.3%**

Monthly Minimum Bill: The Monthly Customer Charge plus the Monthly Demand Charge.

TERMS AND CONDITIONS OF SERVICE:

1. To the extent that this Rate Schedule does not specifically address matters set out in PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** then the provisions in those Parts shall apply, as contemplated therein, to service under this Rate Schedule.

2. **Unaccounted for Gas (UFG) Adjustment Factor**:

   The Applicant is required to deliver to the Company on a daily basis the sum of: (a) the volume of gas to be delivered to the Applicant's Terminal Location; and (b) a volume of gas equal to the forecast unaccounted for gas percentage as stated above multiplied by (a). In the case of a Dedicated Service, the Unaccounted for Gas volume requirement is not applicable.

3. **Nominations**:

   Customer shall nominate gas delivery daily based on the gross commodity delivery required to serve the customer's daily load plus the UFG. Customers may change daily nominations based on the nomination windows within a day as defined by the customer contract with TransCanada PipeLines (TCPL) or Union Gas Limited.

   Schedule of nominations under Rate 125 has to match upstream nominations. This rate does not allow for any more flexibility than exists upstream of the EGD gas distribution system. Where the customer's nomination does not match the confirmed upstream nomination, the nomination will be confirmed at the upstream value.

   Customer may nominate gas to a contractually specified Primary Delivery Area that may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA). The Company may accept deliveries at a Secondary Delivery Area such as Dawn, at its sole discretion. Quantities of gas nominated to the system cannot exceed the Contract Demand, unless Make-up Gas or Authorized Overrun is permitted.

Customers with multiple Rate 125 contracts within a Primary Delivery Area may combine nominations subject to system operating requirements and subject to the Contract Demand for each Terminal Location. For combined nominations the customer shall specify the quantity of gas to each Terminal Location and the order in which gas is to be delivered to each Terminal Location. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location. When system conditions require delivery to a single Terminal Location only, nominations with different Terminal Locations may not be combined.

The Company permits pooling of Rate 125 contracts for legally related customers who meet the Business Corporations Act (Ontario) ("OBCA") definition of "affiliates" to allow for the management of those contracts by a single manager. The single manager is jointly liable with the individual customers for all of their obligations under the contracts, while the individual customers are severally liable for all of their obligations under their own contracts.

4. **Authorized Demand Overrun:**

The Company may, at its sole discretion, authorize consumption of gas in excess of the Contract Demand for limited periods within a month, provided local distribution facilities have sufficient capacity to accommodate higher demand. In such circumstances, customer shall nominate gas delivery based on the gross commodity delivery (the sum of the customer's Contract Demand and the authorized overrun amount) required to serve the customer's daily load, plus the UFG. In the event that gas usage exceeds the gas delivery on a day where demand overrun is authorized, the excess gas consumption shall be deemed Supply Overrun Gas.
Such service shall not exceed 5 days in any contract year. Based on the terms of the Service Contract, requests beyond 5 days will constitute a request for a new Contract Demand level with retroactive charges. The new Contract Demand level may be restricted by the capability of the local distribution facilities to accommodate higher demand.

Automatic authorization of transportation overrun over the Billing Contract Demand will be given in the case of Dedicated Service to the Terminal Location provided that pipeline capacity is available and subject to the Contract Demand as specified in the Service Contract.

Authorized Demand Overrun Rate	**0.29 ¢/m³**

The Authorized Demand Overrun Rate may be applied to commissioning volumes at the Company's sole discretion, for a contractual period of not more than one year, as specified in the Service Contract.

5. **Unauthorized Demand Overrun:**

Any gas consumed in excess of the Contract Demand and/or maximum hourly flow requirements, if not authorized, will be deemed to be Unauthorized Demand Overrun gas. Unauthorized Demand Overrun gas may establish a new Contract Demand effective immediately and shall be subject to a charge equal to 120 % of the applicable monthly charge for twelve months of the current contract term, including retroactively based on terms of Service Contract. Based on capability of the local distribution facilities to accommodate higher demand, different conditions may apply as specified in the applicable Service Contract. Unauthorized Demand Overrun gas shall also be subject to Unauthorized Supply Overrun provisions.

6. **Unauthorized Supply Overrun:**

Any volume of gas taken by the Applicant on a day at the Terminal Location which exceeds the sum of:

i. any applicable provisions of Rate 315 and any applicable Load Balancing Provision pursuant to Rate 125, plus

ii. the volume of gas delivered by the Applicant on that day shall constitute Unauthorized Supply Overrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Overrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 125.

Any gas deemed to be Unauthorized Overrun gas shall be purchased by the customer at a price (Pe), which is equal to 150% of the highest price in effect for that day as defined below***.**

7. **Unauthorized Supply Underrun:**

Any volume of gas delivered by the Applicant on any day in excess of the sum of:

i. any applicable provisions of Rate 315 and any applicable Load Balancing Provision pursuant to Rate 125, plus

ii. the volume of gas taken by the Applicant at the Terminal Location on that day shall be classified as Supply Underrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Underrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 125.

Any gas deemed to be Unauthorized Supply Underrun Gas shall be purchased by the Company at a price (P_u) which is equal to fifty percent (50%) of the lowest price in effect for that day as defined below**.

* where the price P_e expressed in cents / cubic metre is defined as follows:
$P_e = (P_m * E_r * 100 * 0.03769 / 1.055056) * 1.5$

P_m = highest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

E_r = Noon day spot exchange rate expressed in Canadian dollars per U.S. dollar for such day quoted by the Bank of Canada in the following day's Globe & Mail Publication.

1.055056 = Conversion factor from mmBtu to GJ.

0.03769 = Conversion factor from GJ to cubic metres.

** where the price P_u expressed in cents / cubic metre is defined as follows:
$P_u = (P_l * E_r * 100 * 0.03769 / 1.055056) * 0.5$

P_l = lowest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

Term of Contract:

A minimum of one year. A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer. Migration from an unbundled rate to bundled rate may be restricted subject to availability of adequate transportation and storage assets.

Right to Terminate Service:

The Company reserves the right to terminate service to customers served hereunder where the customer's failure to comply with the parameters of this rate schedule, including the load balancing provisions, jeopardizes either the safety or reliability of the gas system. The Company shall provide notice to the customer of such termination; however, no notice is required to alleviate emergency conditions.

LOAD BALANCING PROVISIONS:

Load Balancing Provisions shall apply at the customer's Terminal Location or at the location of the meter installation for a customer served from a dedicated facility. In the event of an imbalance any excess delivery above the customer's actual consumption or delivery less than the actual consumption shall be subject to the Load Balancing Provisions.

Definitions:

Aggregate Delivery:

The Aggregate Delivery for a customer's account shall equal the sum of the confirmed nominations of the customer for delivery of gas to the applicable delivery area from all pipeline sources including where applicable, the confirmed nominations of the customer for Storage Service under Rate 316 or Rate 315 and any available No-Notice Storage Service under Rate 315 for delivery of gas to the Applicable Delivery Area.

Applicable Delivery Area:

The Applicable Delivery Area for each customer shall be specified by contract as a Primary Delivery Area. Where system-operating conditions permit, the Company, in its sole discretion, may accept a Secondary Delivery Area as the Applicable Delivery Area by confirming the customer's nomination of such area. Confirmation of a Secondary Delivery Area for a period of a gas day shall cause such area to become the Applicable Delivery Area for such day. Where delivery occurs at both a Terminal Location and a Secondary Delivery Area on a given day, the sum of the confirmed deliveries may not exceed the Contract Demand, unless Demand Overrun and/or Make-up Gas is authorized.

Primary Delivery Area:

The Primary Delivery Area shall be delivery area such as EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA).

Secondary Delivery Area:

A Secondary Delivery Area may be a delivery area such as Dawn where the Company, at its sole discretion, determines that operating conditions permit gas deliveries for a customer.

Actual Consumption:

The Actual Consumption of the customer shall be the metered quantity of gas consumed at the customer's Terminal Location or in the event of combined nominations at the Terminal Locations specified.

Net Available Delivery:

The Net Available Delivery shall equal the Aggregate Delivery times one minus the annually determined percentage of Unaccounted for Gas (UFG) as reported by the Company.

Daily Imbalance:

The Daily Imbalance shall be the absolute value of the difference between Actual Consumption and Net Available Delivery.

Cumulative Imbalance (also referred to as Banked Gas Account):

The Cumulative Imbalance shall be the sum of the difference between Actual Consumption and Net Available Delivery since the date the customer last balanced or was deemed to have balanced its cumulative imbalance account.

Maximum Contractual Imbalance:

The Maximum Contractual Imbalance shall be equal to 60% of the customer's Contract Demand for non dedicated service and 60% of the Billing Contract Demand for dedicated service.

Winter and Summer Seasons:

The winter season shall commence on the date that the Company provides notice of the start of the winter period and conclude on the date that the Company provides notice of the end of the winter period. The summer season shall constitute all other days. The Company shall provide advance notice to the customer of the start and end of the winter season as soon as reasonably possible, but in no event not less than 2 days prior to the start or end.

Operational Flow Order:

An Operational Flow Order (OFO) shall constitute an issuance of instructions to protect the operational capacity and integrity of the Company's system, including distribution and/or storage assets, and/or connected transmission pipelines.

Enbridge Gas Distribution, acting reasonably, may call for an OFO in the following circumstances:

- Capacity constraint on the system, or portions of the system, or upstream systems, that are fully utilized;
- Conditions where the potential exists that forecasted system demand plus reserves for short notice services provided by the Company and allowances for power generation customers' balancing requirements would exceed facility capabilities and/or provisions of 3rd party contracts;
- Pressures on the system or specific portions of the system are too high or too low for safe operations;
- Storage system constraints on capacity or pressure or caused by equipment problems resulting in limited ability to inject or withdraw from storage;
- Pipeline equipment failures and/or damage that prohibits the flow of gas;
- Any and all other circumstances where the potential for system failure exists.

Daily Balancing Fee:

On any day where the customer has a Daily Imbalance the customer shall pay a Daily Balancing Fee equal to:

(Tier 1 Quantity X Tier 1 Fee) + (Tier 2 Quantity X Tier 2 Fee) + (Applicable Penalty Fee for Imbalance in excess of the Maximum Contractual Imbalance X the amount of Daily Imbalance in excess of the Maximum Contractual Imbalance)

Where Tier 1 and 2 Fees and Quantities are set forth as follows:

Tier 1 = 0.8857 cents/m3 applied to Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance

Tier 2 = 1.0628 cents/m3 applied to Daily Imbalance of greater than 10% but less than the Maximum Contractual Imbalance

In addition for Tier 2, instances where the Daily Imbalance represents an under delivery of gas during the winter season shall constitute Unauthorized Supply Overrun Gas for all gas in excess of 10% of Maximum Contractual Imbalance. Where the Daily Imbalance represents an over delivery of gas during the summer season, the Company reserves the right to deem as Unauthorized Supply Underrun Gas for all gas in excess of 10% of Maximum Contractual Imbalance. The Company will issue a 24-hour advance notice to customers of its intent to impose cash out for over delivery of gas during the summer season.

The customers shall also pay any Load Balancing Agreement (LBA) charges imposed by the pipeline on days when the customer has a Daily Imbalance provided such imbalance matches the direction of the pipeline imbalance. LBA charges shall first be allocated to customers served under Rates 125 and 300. The system bears a portion of these charges only to the extent that the system incurs such charges based on its operation excluding the operation of customers under Rates 125 and 300. In that event, LBA charges shall be prorated based on the relative imbalances. The Company will provide the customer with a derivation of any such charges.

Customer's Actual Consumption cannot exceed Net Available Delivery when the Company issues an Operational Flow Order in the winter. Net nominations must not be less than consumption at the Terminal Location. Any negative Daily Imbalance on a winter Operational Flow Order day shall be deemed to be Unauthorized Supply Overrun. Customer's Net Available Delivery cannot exceed Actual Consumption when the Company issues an Operational Flow Order in the summer. Actual Consumption must not be less than net nomination at the Terminal Location. Any positive Daily Imbalance on a summer Operational Flow Order day shall be deemed to be Unauthorized Supply Underrun.

The Company will waive Daily Balancing Fee and Cumulative Imbalance Charge on the day of an Operational Flow Order if the customer used less gas that the amount the customer delivered to the system during the winter season or the customer used more gas than the amount the customer delivered to the system during the summer season. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders and suspension of Load Balancing Provisions.

Cumulative Imbalance Charges:

Customers may trade Cumulative Imbalances within a delivery area. Customers may also title transfer gas from their Cumulative Imbalances Account (Banked Gas Account) into a Rate 316 storage account of the customer provided that the customer has space available in the storage account to accommodate the transfer.

Customers shall be permitted to nominate Make-up Gas, subject to operating constraints, provided that Make-up Gas plus Aggregate Delivery do not exceed the Contract Demand. The Company may, on days with no operating constraints, authorize Make-up Gas that, in conjunction with Aggregate Delivery, exceeds the Contract Demand.

The customer's Cumulative Imbalance cannot exceed its Maximum Contractual Imbalance. In the event that the customer cannot title transfer gas from their Cumulative Imbalances Account (Banked Gas Account) in whole or in part to storage the Company shall deem the excess imbalance to be Unauthorized Overrun or Underrun gas, as appropriate.

The Cumulative Imbalance Fee shall be equal to 0.9999 cents/m3 per unit of imbalance.

In addition, on any day that the Company declares an Operational Flow Order, negative Cumulative Imbalances greater than 10 % of Maximum Contractual Imbalance in the winter season shall be deemed to be Unauthorized Overrun Gas. The Company reserves the right to deem positive Cumulative Imbalances greater than 10% of Maximum Contractual Imbalance in the summer season as Unauthorized Supply Underun Gas. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders including cash out instructions for Cumulative Imbalances greater than 10 % of Maximum Contractual Imbalance.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on or after July 1, 2007 or such earlier date as the Board may specify. This rate schedule is effective July 1, 2007 or such earlier date as the Board may specify.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 340,000 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure. A maximum of five percent of the contracted annual volume may be taken by the Applicant in a single month during the months of December to March inclusively.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month	
	December to March	**April to November**
Monthly Customer Charge	**\$110.53**	**\$110.53**
Delivery Charge		
For the first 14,000 m³ per month	**6.6488 ¢/m³**	**1.9488 ¢/m³**
For the next 28,000 m³ per month	**5.4488 ¢/m³**	**1.2488 ¢/m³**
For all over 42,000 m³ per month	**5.0488 ¢/m³**	**1.0488 ¢/m³**
Gas Supply Load Balancing Charge	**2.5757 ¢/m³**	**2.5757 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**34.0023 ¢/m³**	**34.0023 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the average price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Failure to deliver a volume of gas equal to the Mean Daily Volume set out in the Service Contract during the months of December to March inclusive may result in the Applicant not being eligible for service under this rate in a subsequent contract period, at the Company's sole discretion.

SEASONAL CREDIT:

Rate per cubic metre of Mean Daily Volume from December to March **\$ 0.77 /m³**

RATE NUMBER: **135**

SEASONAL OVERRUN CHARGE:

During the months of December through March inclusively, any volume of gas taken in a single month in excess of five percent of the annual contract volume (Seasonal Overrun Monthly Volume) will be subject to Seasonal Overrun Charges in place of both the Delivery and Gas Supply Load Balancing Charges. The Seasonal Overrun Charge applicable for the months of December and March shall be calculated as 2.0 times the sum of the Gas Supply Load Balancing Charge and the maximum Delivery Charge. The Seasonal Overrun Charge applicable for the months of January and February shall be calculated as 5.0 times the sum of the Load Balancing Charge and the maximum Delivery Charge.

Seasonal Overrun Charges:

December and March	**18.4490 ¢/m³**
January and February	**46.1225 ¢/m³**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**5.9936 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service as ordered by the Company exercising its sole discretion. Any Applicant for service under this rate schedule must agree to transport a minimum annual volume of 340,000 cubic metres.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than 72 hours prior to the time at which such curtailment or discontinuance is to commence. An Applicant may, by contract, agree to accept a shorter notice period.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$117.11**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**8.0000 ¢/m³**
For the first 14,000 m³ per month	**2.8296 ¢/m³**
For the next 28,000 m³ per month	**1.4706 ¢/m³**
For all over 42,000 m³ per month	**0.9116 ¢/m³**
Gas Supply Load Balancing Charge	**4.0740 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**34.0363 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 16 hours of notice per cubic metre of Mean Daily Volume from December to March	**$**	**0.50 /m³**
Rate for 72 hours of notice per cubic metre of Mean Daily Volume from December to March	**$**	**0.11 /m³**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations. For any location presently served or any new Applicant for service pursuant to this Rate Schedule in these areas, the Company shall purchase the rights to take service hereunder at 1.25 ¢/m³ per unit of Daily Capacity Repurchase Quantity.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the average price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

The third instance of such failure in any contract year may result in the Applicant forfeiting the right to be served under this Rate Schedule. In such case service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**6.8060 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas of not less than 30,000 cubic metres and a minimum annual volume of 5,000,000 cubic metres to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service when required by the Company. The Company, exercising its sole discretion, may order interruption of gas service upon not less than four (4) hours notice.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than 4 hours prior to the time at which such curtailment or discontinuance is to commence.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$268.95**
Delivery Charge	
Per cubic metre of Contract Demand	**4.0300 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.5113 ¢/m³**
For all over 1,000,000 m³ per month	**0.3113 ¢/m³**
Gas Supply Load Balancing Charge	**3.4209 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.9398 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 4 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 1.10 /m³**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations. For any location presently served or any new Applicant for service pursuant to this Rate Schedule in these areas, the Company shall purchase the rights to take service hereunder at 1.25 ¢/m³ per unit of Daily Capacity Repurchase Quantity.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the average price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

The third instance of such failure in any contract year may result in the Applicant forfeiting the right to be served under this Rate Schedule. In such case service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **3.8346 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

APPLICABILITY:

To any Distributor who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of an annual supply of natural gas to customers outside of the Company's franchise area.

CHARACTER OF SERVICE:

Service shall be continuous (firm), except for events as specified in the Service Contract including force majeure, up to the contracted firm daily demand and subject to curtailment or discontinuance, of demand in excess of the firm contract demand, upon the Company issuing a notice not less than 4 hours prior to the time at which such curtailment or discontinuance is to commence.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month **January to December**
Monthly Customer Charge	
The monthly customer charge shall be negotiated with the applicant and shall not exceed:	**$2,000.00**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**13.8300 ¢/m³**
Per cubic metre of gas delivered	**0.9629 ¢/m³**
Gas Supply Load Balancing Charge	**4.3007 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.9398 ¢/m³**
Buy/Sell Sales Gas Supply Charge per cubic metre (If applicable)	**33.9212 ¢/m³**

The rates quoted above shall be subject to the Gas Inventory Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable to volumes of natural gas purchased from the Company. The volumes purchased shall be the volumes delivered at the Point of Delivery less any volumes, which the Company does not own and are received at the Point of Acceptance for delivery to the Applicant at the Point of Delivery.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 4 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 1.10 /m³**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations. For any location presently served or any new Applicant for service pursuant to this Rate Schedule in these areas, the Company shall purchase the rights to take service hereunder at 1.25 ¢/m³ per unit of Daily Capacity Repurchase Quantity.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the average price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

The third instance of such failure in any contract year may result in the Applicant forfeiting the right to be served under this Rate Schedule. In such case service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**5.1661 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2007 under Sales Service including Buy/Sell Arrangements and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

RATE NUMBER: **300**	**FIRM OR INTERRUPTIBLE DISTRIBUTION SERVICE**

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation to a single Terminal Location of a specified maximum daily volume of natural gas. The Company reserves the right to limit service under this schedule to customers whose maximum contract demand does not exceed 600,000 m3. The Service under this rate requires Automatic Meter Reading (AMR) capability. Service under this schedule is firm unless a customer is currently served under interruptible distribution service or the Company, in its sole judgment, determines that existing delivery facilities cannot adequately serve the load on a firm basis.

The unitized Monthly Contract Demand Charge is also applicable to volumes delivered to any Applicant taking service under a Curtailment Delivered Supply contract with the Company. The unitized rate equals the applicable Monthly Contract Demand Charge times 12/365.

CHARACTER OF SERVICE:

The Service shall be continuous (firm) except for events specified in the Service Contract including force majeure. The Applicant is neither allowed to take a daily quantity of gas greater than the Contract Demand nor an hourly amount in excess of the Contract Demand divided by 24, without the Company's prior consent. Interruptible Distribution Service is provided on a best efforts basis subject to the events identified in the service contract including force majeure and, in addition, shall be subject to curtailment or discontinuance of service when the Company notifies the customer under normal circumstances 4 hours prior to the time that service is subject to curtailment or discontinuance. Under emergency conditions, the Company may curtail or discontinue service on one-hour notice. The Interruptible Service Customer is not allowed to exceed maximum hourly flow requirements as specified in Service Contract.

DISTRIBUTION RATES:

Monthly Customer Charge	**$500.00**
Monthly Contract Demand Charge Firm	**24.0202 ¢/m³**
Interruptible Service:	
Minimum Delivery Charge	**0.3512 ¢/m³**
Maximum Delivery Charge	**0.9476 ¢/m³**
Forecast Unaccounted For Gas Percentage	**0.3%**

Monthly Minimum Bill: The Monthly Customer Charge plus the Monthly Contract Demand Charge.

TERMS AND CONDITIONS OF SERVICE:

1. To the extent that this Rate Schedule does not specifically address matters set out in PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** then the provisions in those Parts shall apply, as contemplated therein, to service under this Rate Schedule.

2. **Unaccounted for Gas (UFG) Adjustment Factor**:

   The Applicant is required to deliver to the Company on a daily basis the sum of: (a) the volume of gas to be delivered to the Applicant's Terminal Location; and (b) a volume of gas equal to the forecast unaccounted for gas percentage as stated above multiplied by (a).

3. **Nominations**:

   Customer shall nominate gas delivery daily based on the gross commodity delivery required to serve the customer's daily load plus the UFG, net of No-Notice Storage Service provisions under Rate 315, if applicable. The amount of gas delivered under No-Notice Storage Service will also be reduced by the UFG adjustment factor for delivery to the customer's meter.

   Customers may change daily nominations based on the nomination windows within a day as defined by the customer contract with TransCanada PipeLines (TCPL) or Union Gas Limited.

   Schedule of nominations under Rate 300 has to match upstream nominations. This rate does not allow for any more flexibility than exists upstream of the EGD gas distribution system. Where the customer's nomination does not match the confirmed upstream nomination, the nomination will be confirmed at the upstream value.

Customer may nominate gas to a contractually specified Primary Delivery Area that may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA). The Company may accept deliveries at a Secondary Delivery Area such as Dawn, at its sole discretion. Quantities of gas nominated to the system cannot exceed Contract Demand, unless Make-up Gas or Authorized Overrun is permitted.

Customers with multiple Rate 300 contracts within a Primary Delivery Area may combine nominations subject to system operating requirements and subject to the Contract Demand for each Terminal Location. For combined nominations the customer shall specify the quantity of gas to each Terminal Location and the order in which gas is to be delivered to each Terminal Location. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location. When system conditions require delivery to a single Terminal Location only, nominations with different Terminal Locations may not be combined.

4. **Authorized Demand Overrun:**

The Company may, at its sole discretion, authorize consumption of gas in excess of the Contract Demand for limited periods within a month, provided local distribution facilities have sufficient capacity to accommodate higher demand. In such circumstances, customer shall nominate gas delivery based on the gross commodity delivery required to serve the customer's daily load, including quantities of gas in excess of the Contract Demand, plus the UFG. The Load Balancing Provisions and/or No-Notice Storage Service provisions under Rate 315 cannot be used for Authorized Demand Overrun. Failure to nominate gas deliveries to match Authorized Demand Overrun shall constitute Unauthorized Supply Overrun.

The rate applicable to Authorized Demand Overrun shall equal the applicable Monthly Demand Charge times 12/365 provided, however, that such service shall not exceed 5 days in any contract year. Requests beyond 5 days will constitute a request for a new Contract Demand level, with retroactive charges based on terms of Service Contract.

5. **Unauthorized Demand Overrun:**

Any gas consumed in excess of the Contract Demand and/or maximum hourly flow requirements, if not authorized, will be deemed to be Unauthorized Demand Overrun gas. Unauthorized Demand Overrun gas will establish a new Contract Demand and shall be subject to a charge equal to 120 % of the applicable monthly charge for twelve months of the current contract term, including retroactively based on terms of Service Contract. Unauthorized Demand Overrun gas shall also be subject to Unauthorized Supply Overrun provisions. Where a customer receives interruptible service hereunder and consumes gas during a period of interruption, such gas shall be deemed Unauthorized Supply Overrun. In addition to charges for Unauthorized Supply Overrun, interruptible customers consuming gas during a scheduled interruption shall pay a penalty charge of $18.00 per m3.

6. **Unauthorized Supply Overrun:**

Any volume of gas taken by the Applicant on a day at the Terminal Location which exceeds the sum of:

i. any applicable Load Balancing Provision pursuant to Rate 300 and/or provisions of Rate 315, plus

ii. the volume of gas delivered by the Applicant on that day shall constitute Unauthorized Supply Overrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Overrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 300.

Any gas deemed to be Unauthorized Overrun gas shall be purchased by the customer at a price (Pe), which is equal to 150% of the highest price in effect for that day as defined below*.

7. **Unauthorized Supply Underrun:**

Any volume of gas delivered by the Applicant on any day in excess of the sum of:

i. any applicable Rate 300 Load Balancing Provision pursuant to Rate 300 and/or provisions of Rate 315, plus

ii. the volume of gas taken by the Applicant at the Terminal Location on that day shall be classified as Supply Underrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Underrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 300.

Any gas deemed to be Unauthorized Supply Underrun Gas shall be purchased by the Company at a price (P_u) which is equal to fifty percent (50%) of the lowest price in effect for that day as defined below**.

* where the price P_e expressed in cents / cubic metre is defined as follows:
$P_e = (P_m * E_r * 100 * 0.03769 / 1.055056) * 1.5$

P_m = highest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

E_r = Noon day spot exchange rate expressed in Canadian dollars per U.S. dollar for such day quoted by the Bank of Canada in the following days Globe & Mail Publication.

1.055056 = Conversion factor from mmBtu to GJ.

0.03769 = Conversion factor from GJ to cubic metres.

** where the price P_u expressed in cents / cubic metre is defined as follows:
$P_u = (P_l * E_r * 100 * 0.03769 / 1.055056) * 0.5$

P_l = lowest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

Term of Contract:

A minimum of one year. A longer-term contract may be required if incremental assets/facilities have been procured/built for the customer. Migration from an unbundled rate to bundled rate may be restricted subject to availability of adequate transportation and storage assets.

Right to Terminate Service:

The Company reserves the right to terminate service to customers served hereunder where the customer's failure to comply with the parameters of this rate schedule, including interruptible service and load balancing provisions, jeopardizes either the safety or reliability of the gas system. The Company shall provide notice to the customer of such termination; however, no notice is required to alleviate emergency conditions.

Load Balancing:

Any difference between actual daily-metered consumption and the actual daily volume of gas delivered to the system less the UFG shall first be provided under the provisions of Rate 315 - Gas Storage Service, if applicable. Any remaining difference will be subject to the Load Balancing Provisions.

LOAD BALANCING PROVISIONS:

Load Balancing Provisions shall apply at the customer's Terminal Location.

In the event of an imbalance any excess delivery above the customer's actual consumption or delivery less than the actual consumption shall be subject to the Load Balancing Provisions.

Definitions:

Aggregate Delivery:

The Aggregate Delivery for a customer's account shall equal the sum of the confirmed nominations of the customer for delivery of gas to the applicable delivery area from all pipeline sources plus, where applicable, the confirmed nominations of the customer for Storage Service under Rate 316 or Rate 315 and any available No-Notice Storage Service under Rate 315 for delivery of gas to the Applicable Delivery Area.

Applicable Delivery Area:

The Applicable Delivery Area for each customer shall be specified by contract as a Primary Delivery Area. Where system-operating conditions permit, the Company, in its sole discretion, may accept a Secondary Delivery Area as the Applicable Delivery Area by confirming the customer's nomination of such area. Confirmation of a Secondary Delivery Area for a period of a gas day shall cause such area to become the Applicable Delivery Area for such day. Where delivery occurs at both a Terminal Location and a Secondary Delivery Area on a given day, the sum of the confirmed deliveries may not exceed Contract Demand, unless Demand Overrun and/or Make-up Gas is authorized.

Primary Delivery Area:

The Primary Delivery Area shall be delivery area such as EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA).

Secondary Delivery Area:

A Secondary Delivery Area may be a delivery area such as Dawn where the Company, at its sole discretion, determines that operating conditions permit gas deliveries for a customer.

Actual Consumption:

The Actual Consumption of the customer shall be the metered quantity of gas consumed at the customer's premise.

Net Available Delivery:

The Net Available Delivery shall equal the Aggregate Delivery times one minus the annually determined percentage of Unaccounted for Gas (UFG) as reported by the Company.

Daily Imbalance:

The Daily Imbalance shall be the absolute value of the difference between Actual Consumption and Net Available Delivery.

Cumulative Imbalance (also referred to as Banked Gas Account):

The Cumulative Imbalance shall be the sum of the difference between Actual Consumption and Net Available Delivery.

Maximum Contractual Imbalance:

The Maximum Contractual Imbalance shall be equal to 60% of the customer's Contract Demand.

Winter and Summer Seasons:

The winter season shall commence on the date that the Company provides notice of the start of the winter period and conclude on the date that the Company provides notice of the end of the winter period. The summer season shall constitute all other days. The Company shall provide advance notice to the customer of the start and end of the winter season as soon as reasonably possible, but in no event not less than 2 days prior to the start or end.

Operational Flow Order:

An Operational Flow Order (OFO) shall constitute an issuance of instructions to protect the operational capacity and integrity of the Company's system, including distribution and/or storage assets, and/or connected transmission pipelines.

Enbridge Gas Distribution, acting reasonably, may call for an OFO in the following circumstances:

- Capacity constraint on the system, or portions of the system, or upstream systems, that are fully utilized;
- Conditions where the potential exists that forecasted system demand plus reserves for short notice services provided by the Company and allowances for power generation customers' balancing requirements would exceed facility capabilities and/or provisions of 3rd party contracts;
- Pressures on the system or specific portions of the system are too high or too low for safe operations;
- Storage system constraints on capacity or pressure or caused by equipment problems resulting in limited ability to inject or withdraw from storage;
- Pipeline equipment failures and/or damage that prohibits the flow of gas;
- Any and all other circumstances where the potential for system failure exists.

Daily Balancing Fee:

On any day where the customer has a Daily Imbalance the customer shall pay a Daily Balancing Fee equal to:

(Tier 1 Quantity X Tier 1 Fee) + (Tier 2 Quantity X Tier 2 Fee) + (Applicable Penalty Fee for Imbalance in excess of the Maximum Contractual Imbalance X the amount of Daily Imbalance in excess of the Maximum Contractual Imbalance)

Where Tier 1 and 2 Fees and Quantities are set forth as follows:

Tier 1 = Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance and shall be subject to a charge of 0.8857 cents/M3

Tier 2 = Daily Imbalance of greater than 10% but less than Maximum Contractual Imbalance shall be subject to a charge of 1.0628 cents/m3

The customers shall also pay any Load Balancing Agreement (LBA) charges imposed by the pipeline on days when the customer has a Daily Imbalance provided such imbalance matches the direction of the pipeline imbalance. LBA charges shall first be allocated to customers served under Rate 125 and 300. The system bears a portion of these charges only to the extent that the system incurs such charges based on its operation excluding the operation of customers under Rates 125 and 300. In that event, LBA charges shall be prorated based on the relative imbalances.

A Daily Imbalance in excess of the Maximum Contractual Imbalance shall be deemed to be Unauthorized Supply Overrun or Underrun gas, as appropriate.

Customer's Actual Consumption cannot exceed Net Available Delivery when the Company issues an Operational Flow Order in the winter. Net nominations must not be less than consumption at the Terminal Location. Any negative Daily Imbalance on a winter Operational Flow Order day shall be deemed to be Unauthorized Supply Overrun. Customer's Net Available Delivery cannot exceed Actual Consumption when the Company issues an Operational Flow Order in the summer. Actual Consumption must not be less than net nomination at the Terminal Location. Any positive Daily Imbalance on a summer Operational Flow Order day shall be deemed to be Unauthorized Supply Underrun.

The Company will waive Daily Balancing Fee and Cumulative Imbalance Charge on the day of an Operational Flow Order if the customer used less gas that the amount the customer delivered to the system during the winter season or the customer used more gas than the amount the customer delivered to the system during the summer season. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders and suspension of Load Balancing Provisions.

Cumulative Imbalance Charges:

Customers may trade Cumulative Imbalances within a delivery area.

Customers shall be permitted to nominate Make-up Gas, subject to operating constraints, provided that Make-up Gas plus Aggregate Delivery do not exceed Contract Demand. The Company may, on days with no operating constraints, authorize Make-up Gas that, in conjunction with Aggregate Delivery, exceeds Contract Demand.

The customer's Cumulative Imbalance cannot exceed its Maximum Contractual Imbalance. The excess imbalance shall be deemed to be Unauthorized Overrun or Underrun gas, as appropriate.

The Cumulative Imbalance Fee shall be equal to of 0.4362 cents/m3 per unit of imbalance.

The customer's Cumulative Imbalance shall be equal to zero within five (5) days from the last day of the Service Contract.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on or after January 1, 2007, or, on or after April 1, 2007, depending on the start date chosen by the customer. This rate schedule is effective January 1, 2007.

APPLICABILITY:

This rate is available to any customer taking service under Distribution Rates 125 and 300. It requires a Service Contract that identifies the required storage space and deliverability. In addition, the customer shall maintain a positive balance of gas in storage at all times or forfeit the use of Storage Services for Load Balancing and No-Notice Storage Service.

A daily nomination for storage injection and withdrawal except for No-Notice Storage Service, hereunder, which is used automatically for daily Load Balancing, shall also be required.

The maximum hourly injections / withdrawals shall equal 1/24th of the daily Storage Demand. No-Notice Storage Service is available up to the maximum daily withdrawal rights less the nominated withdrawal or the maximum daily injection rights less the nominated injections.

Storage space shall be based on the storage space algorithm [(customer's average winter demand – customer's average annual demand) x 151]. Gas fired power generation customers have the option to have storage space determined based on the methodology approved in EB-2005-0551.

Maximum deliverability shall be 1.2% of contracted storage space. The customer may inject and withdraw gas based on the quantity of gas in storage and the limitations specified in the Service Contract. Both injection and withdrawal shall be subject to applicable storage ratchets as determined by the Company and posted from time to time.

CHARACTER OF SERVICE:

Service shall be firm when used in conjunction with firm distribution service. Service is interruptible when used in conjunction with interruptible distribution service. All service is subject to contract terms and force majeure.

The service is available on two bases:

(1) Service nominated daily based on the available capacity and gas in storage up to the maximum contracted daily deliverability; and

(2) No-Notice Storage Service for daily Load Balancing consistent with the maximum hourly deliverability.

RATE:

The following rates and charges shall apply in respect to all gas received by the Company from and delivered by the Company to storage on behalf of the Applicant.

Monthly Customer Charge:	**$150.00**
Storage Reservation Charge:	
Monthly Storage Space Demand Charge	**0.0346 ¢/m³**
Monthly Storage Deliverability/Injection Demand Charge	**12.0982 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.4999 ¢/m³**

Monthly Minimum Bill: The sum of the Monthly Customer Charge plus Monthly Demand Charges.

FUEL RATIO REQUIREMENT:

The Fuel Ratio per unit of gas injected and withdrawn is 0.35%.

All Storage Space and Deliverability/Injection Demand Charges are applicable monthly. Injection and withdrawal charges are applicable to each unit of gas injected or withdrawn based on daily nominations and No-Notice Storage Service quantities.

All deemed withdrawal quantities under the No-Notice Storage Service provisions of this rate will be adjusted for the UFG provisions applicable to the distribution service rates.

In addition, for each unit of injection or withdrawal there will be an applicable fuel charge adjustment expressed as a percent of gas.

TERMS AND CONDITIONS OF SERVICE:

1. **Nominated Storage Service**:

Nominations under this rate shall only be accepted at the standard North American Energy Standards Board ("NAESB") nomination windows. The customer may elect to nominate all or a portion of the available withdrawal capacity for delivery to the applicable Primary Delivery Area, which may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA). All volumes nominated from storage are delivered first for purposes of daily Load Balancing of available supply assets. When system conditions permit, the customer may nominate all or a portion of the available withdrawal capacity for delivery to Dawn or to the customer's Primary Delivery Area for purposes other than consumption at the customer's own meter.

Storage not nominated for delivery will be available for No-Notice Storage Service. The sum of gas nominated for storage injection and for the Terminal Location shall not exceed the customer's Contract Demand (CD).

The customer may also nominate gas for delivery into storage by nominating the storage delivery area as the Primary Delivery Area. Gas nominated for storage delivery will not be available for No-Notice Storage Service. The sum of gas nominated for storage injection and for the Terminal Location shall not exceed the customer's CD.
Any gas in excess of the contract demand will be subject to cash out as injection overrun gas.

The Company reserves the right to limit injection and withdrawal rights to all storage customers in certain situations, such as major maintenance or construction projects, and may reduce nominations for injections and withdrawals over and above applicable storage ratchets. The Company will provide customers with one week's notice of its intent to limit injection and withdrawal rights, and at the same time, shall provide its best estimate of the duration and extent of the limitations.

In situations where the Company limits injection and withdrawal rights, the Company shall proportionately reduce the Storage Deliverability/Injection Demand Charge for affected customers based on the number of days the limitation is in effect and the difference between Deliverability/Injection Demand, subject to applicable storage ratchets, and the quantity of gas actually delivered or injected.

2. **No-Notice Storage Service**:

The Company, at its sole discretion based on operating conditions, may provide a No-Notice Storage Service that allows customers taking gas under distribution service rates to balance daily deliveries using this Storage Service. No-Notice Storage Service requires that the customer grant the Company the exclusive right to use unscheduled service available from storage to reduce the daily imbalance associated with the actual consumption of the customer.

No-Notice Storage Service is limited to the available, unscheduled withdrawal or injection capacity under contract to serve a customer. Where the customer serves multiple delivery locations from a single storage Service Contract, the customer shall specify the order in which gas is to be delivered to each Terminal Location served under a distribution Service Contract. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location.

The availability of No-Notice Storage Service is subject to and reduced by any service schedule from or to storage. To the extent that the quantity of gas available in storage is insufficient to meet the requirements of the customer under a No-Notice Storage Service, the customer will be unable to use the service on a no-notice basis for Load Balancing service. To the extent that the scheduled injections into storage plus No-Notice Storage Service exceed the maximum limit for injection, No-Notice Storage Service will be reduced and the remainder of the gas will constitute a daily imbalance. Gas delivered in excess of the maximum injection quantity shall be deemed injection overrun gas and cashed out at 50% of the lowest index price of gas.

Other provisions

If the customer elects to use the contracted storage capacity at less than the full volumetric capacity of the storage, the Company may inject its own gas provided that such injection does not reduce the right of the customer to withdraw the full amount of gas injected on any day during the withdrawal season or to schedule its full injection right during the injection season.

Term of Contract:

A minimum of one year.

A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on or after January 1, 2007, or, on or after April 1, 2007, depending on the start date chosen by the customer.

This rate schedule is effective January 1, 2007.

APPLICABILITY:

To any Applicant whose delivery of natural gas to the Company for transportation to a Terminal Location has been interrupted prior to the delivery of such gas to the Company.

CHARACTER OF SERVICE:

The volume of gas available for backstopping in any day shall be determined by the Company exercising its sole discretion. If the aggregate daily demand for service under this Rate Schedule exceeds the supply available for such day, the available supply shall be allocated to firm service customers on a first requested basis and any balance shall be available to interruptible customers on a first requested basis.

RATE:

The rates applicable in the circumstances contemplated by this Rate Schedule, in lieu of the Gas Supply Charges specified in any of the Company's other Rate Schedules pursuant to which the Applicant is taking service, shall be as follows:

	Billing Month **January to December**
Gas Supply Charge	
Per cubic metre of gas sold	**37.6720 ¢/m³**

provided that if upon the request of an Applicant, the Company quotes a rate to apply to gas which is delivered to the Applicant at a particular Terminal Location on a particular day or days and to which this Rate Schedule is applicable (which rate shall not be less than the Company's avoided cost in the circumstances at the time nor greater than the otherwise applicable rate specified above), then the Gas Supply Charge applicable to such gas shall be the rate quoted by the Company.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

APPLICABILITY AND CHARACTER OF SERVICE:

Service under this rate schedule shall apply to the Transmission and Compression Service Agreement with Union Gas Limited dated April 1, 1989, and the Transmission, Compression and Pool Storage Service Agreement with Centra Gas Ontario Inc. dated May 30, 1994. Service shall be provided subject to the terms and conditions specified in the Service Agreement.

RATE:

The Customer shall pay for service rendered in each month in a contract year, the sum of the following applicable charges:

	Transmission & Compression $\$/10^3m^3$	**Pool Storage $\$/10^3m^3$**
Demand Charge for:		
Annual Turnover Volume	**0.1652**	**0.1935**
Maximum Daily Withdrawal Volume	**14.9334**	**17.5558**
Commodity Charge	**1.4724**	**0.5817**

FUEL RATIO REQUIREMENT:

Fuel Ratio applicable to per unit of gas injected and withdrawn is 0.35%.

MINIMUM BILL:

The minimum monthly bill shall be the sum of the applicable Demand Charges as stated in Rate Section above.

EXCESS VOLUME AND OVERRUN RATES:

In addition to the charges provided for in the Rate Section above, the Customer shall pay, for services rendered, the sum of the following applicable charges as they are incurred:

TERMS AND CONDITIONS OF SERVICE:

1. Excess Volumes will be billed at the total of the Excess Volume Charges as stated above.

2. Transmission and Compression, and Pool Storage Overrun Service will be billed according to the following:
   (a) At the end of each month, in a contract year, the Company will make a determination, for each day in the month, of

      (i) the difference between the volume of gas actually delivered, exclusive of the fuel volume, for Customer's account into the Company System, at the Point of Delivery and the Customer's Maximum Daily Injection Volume, and

      (ii) the difference between the volume of gas actually delivered, exclusive of the fuel volume, for Customer's account from the Company System, at the Point of Delivery, and the Customer's Maximum Daily Withdrawal Volume.

	Excess Volume Charge $/10³m³ / Year	Overrun Charge $/10³m³ / Day
Transmission & Compression		
Authorized	**2.1804**	**0.4910**
Unauthorized	**-**	**197.1212**
Pool Storage		
Authorized	**2.5549**	**0.5772**
Unauthorized	**-**	**231.7365**

(b) For each day of the month, where any such differences exceed 2.0 percent of the Customer's relevant Maximum Daily Injection Volume and/or Maximum Daily Withdrawal Volume, the Customer shall pay a charge equal to the relevant Overrun rates, as stated above, for such differences.

BILLING ADJUSTMENT:

1. Injection deficiency - If at the beginning of any Withdrawal Period the Customer's Storage Balance is less than the Customer's Annual Turnover Volume, due solely to the Company's inability to inject gas for any reason other than the fault of the Customer, then the applicable Demand Charge for Annual Turnover Volume for the contract year beginning the prior April 1 as stated in Rate Section as applicable, shall be adjusted by multiplying each by a fraction, the numerator of which shall be the Customer's Storage Gas Balance as of the beginning of such Withdrawal Period and the denominator shall be the Customer's Annual Turnover Volume as it may have been established for the then current year.

2. Withdrawal deficiency - If in any month in a contract year for any reason other than the fault of the Customer, the Company fails or is unable to deliver during any one or more days, the amount of gas which the Customer has nominated, up to the maximum volumes which the Company is obligated by the Agreement to deliver to the Customer, then the Demand Charge for maximum Contract Daily Withdrawal Volume in the contract year otherwise payable for the month in which such failure occurs, as stated in Rate Section above, as applicable, shall be reduced by an amount for each day of deficiency to be calculated as follows: The Demand Charge for maximum Contract Daily Withdrawal Volume for the contract year for the month will be divided by 30.4 and the result obtained will then be multiplied by a fraction, the numerator being the difference between the nominated volume for such day and the delivered volume for such day and the denominator being the Customer's maximum Contract Daily Withdrawal Volume for such contract year.

TERMS AND EXPRESSIONS:

In the application of this Rate Schedule to each of the Agreements, terms and expressions used in this Rate Schedule have the meanings ascribed thereto in such Agreement.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2007. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates, as the Board Order, EB-2006-0288.

RATE NUMBER: **330**	**TRANSMISSION AND COMPRESSION AND POOL STORAGE**

APPLICABILITY:

To any Applicant who enters into a Storage Contract with the Company for delivery by the Applicant to the Company and re-delivery by the Company to the Applicant of a volume of natural gas owned by the Applicant.

CHARACTER OF SERVICE:

Service under this rate is for Full Cycle or Short Cycle storage service; with firm or interruptible injection and withdrawal service, all as may be available from time to time.

RATE:

The following rates and charges shall apply in respect of all gas received by the Company from and re-delivered by the Company to the Applicant.

	Full Cycle		**Short Cycle**
	Firm	**Interruptible**	
	$/10³m³	**$/10³m³**	**$/10³m³**
Monthly Demand Charge per unit of Annual Turnover Volume:			
Minimum	**0.3587**	**0.3587**	**-**
Maximum	**1.7936**	**1.7936**	**-**
Monthly Demand Charge per unit of Contracted Daily Withdrawal:			
Minimum	**32.4892**	**25.9914**	**-**
Maximum	**162.4461**	**129.9569**	**-**
Commodity Charge per unit of gas delivered to / received from storage:			
Minimum	**2.0541**	**2.0541**	**0.8942**
Maximum	**10.2706**	**10.2706**	**38.1075**

FUEL RATIO REQUIREMENT:

The Fuel Ratio per unit of gas injected and withdrawn is 0.35%.

TRANSACTING IN ENERGY:

The conversion factor is 37.74MJ/m3, which corresponds to Union Gas' System Wide Average Heating Value, as per the Board's RP-1999-0017 Decision with Reasons.

MINIMUM BILL:

The minimum monthly bill shall be the sum of the applicable Demand Charges.

OVERRUN RATES:

The units rates stated below will apply to overrun volumes. The provision of Authorized Overrun service will be at the Company's sole discretion.

	Full Cycle		Short Cycle
	Firm $/10³m³	Interruptible $/10³m³	$/10³m³
Authorized Overrun			
Annual Turnover Volume			
Negotiable, not to exceed:	**38.1075**	**38.1075**	**38.1075**
Authorized Overrun			
Daily Injection/Withdrawal			
Negotiable, not to exceed:	**38.1075**	**38.1075**	**38.1075**
Unauthorized Overrun			
Annual Turnover Volume			
Excess Storage Balance			
September 1 - November 30	**381.0754**	**381.0754**	**381.0754**
December 1 - October 31	**38.1075**	**38.1075**	**38.1075**
Unauthorized Overrun			
Annual Turnover Volume			
Negative Storage Balance			

TERMS AND CONDITIONS OF SERVICE:

1. All Services are available at the Company's sole discretion.
2. Delivery and Re-delivery of the volume of natural gas shall be from/to the facilities of Union Gas Limited and / or TransCanada PipeLines Limited in Dawn Township and/or Niagara Gas Transmission Limited in Moore Township.
3. The Customers daily injections or withdrawals will be adjusted to provide for the fuel ratio stated in the Fuel Ratio Section. In the event that a Short Cycle service does not require fuel for injection and/or withdrawal, the fuel ratio commodity charge may be waived.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2007. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates, as the Board Order, EB-2006-0288.

APPLICABILITY:

To any Applicant who enters into a Contract with the Company for transportation on the Company's Tecumseh Transmission System.

CHARACTER OF SERVICE:

Service under this rate is for firm transportation service as may be available from time to time.

RATE:

The following rates and charges shall apply in respect of all gas received by the Company from and re-delivered by the Company to the Applicant.

	Firm $\$/10^3m^3$	Interruptible $\$/10^3m^3$
Monthly Demand Charge per unit of Maximum Contracted Daily Delivery:	**4.4780**	**-**
Commodity Charge per unit of gas delivered:	**-**	**0.1770**

MINIMUM BILL:

The minimum monthly bill shall be the sum of the applicable Demand Charges.

TERMS AND CONDITIONS OF SERVICE:

1. Delivery of the volume of natural gas by the Applicant shall be at the interconnection of the Company's Tecumseh transmission facilities with that of Niagara Gas Transmission Limited at the Tecumseh Compressor Station.

2. Re-delivery of the volume of natural gas shall be at the interconnection of the Company's facilities with those of interconnecting pipelines in Dawn Township.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2007. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates, as the Board Order, EB-2006-0288.

Applicants located off the piping networks noted below or off piping systems supplied from these networks may be curtailed to maintain distribution system integrity.

The Town of Collingwood
The Town of Midland

APPLICABILITY:

This rider is applicable to any Applicant who enters into Gas Transportation Agreement with the Company under any rate other than Rates 125 and 300.

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Base Charge	$50.00	per month
Maximum Charge	$815.00	per month
Account Charge		
New Accounts	$0.50	per month per account
Renewal Accounts	$0.15	per month per account

The above Basic Charge shall be increased up to the maximum charge, by the new account charge for each new account and by the Renewal Account charge for each renewal account in a Direct Purchase Contract.

T-SERVICE CREDIT:

In T-Service Arrangements excluding Ontario ABC-T arrangements, between the Company and an Applicant, and with a T-Service Arrangement and a contractually specified Point of Acceptance as indicated below, the Company shall pay or charge the Applicant the Transportation Service Credit or Debit shown for any volumes of natural gas owned by the Applicant and received by the Company at the Point of Acceptance. The ability of the Company to accept deliveries under FT-type arrangements at Dawn is constrained and the availability of this service is at the Company's sole discretion.

TOLLS CREDIT	**Type of Arrangement**	
Point of Acceptance	Firm Transportation (FT)	Firm Service Tendered (FST)
Western Canada	0.0000 ¢/m³	0.0000 ¢/m³
CDA, EDA	3.5241 ¢/m³	0.0000 ¢/m³
Dawn	3.0336 ¢/m³	0.0000 ¢/m³
Intra-Alberta	-0.4649 ¢/m³	N/A

Effective February 1, 2001, in Ontario ABC-T arrangements with a contractually specified Point of Acceptance in the CDA and/or EDA, the toll credit shall equal the Eastern Zone Firm Transportation tolls approved by the National Energy Board for TCPL at a 100% load factor.

<u>TCPL FT CAPACITY TURNBACK:</u>

APPLICABILITY:

To Ontario T-Service customers who have been or will be assigned TCPL capacity by the Company.

TERMS AND CONDITIONS OF SERVICE:

1. The Company will accommodate TCPL FT capacity turnback from customers to the extent that the Company is allowed to turnback FT capacity to TCPL.

2. The Company will accommodate all TCPL FT capacity turnback requests in a manner that minimizes stranded and other transitional costs. The Company is committed to maintaining the integrity of its distribution system and the sanctity of all contracts.

3. The Company may amend any contracts to accommodate a customer's request to turnback capacity.

4. Notice of TCPL FT turnback capacity will be accepted on Enbridge's Election for Enbridge Firm Transportation Assignment form or other authorized written notice.

5. The daily contractual right to receive natural gas would still be subject to the delivery, on a firm basis, of the full Mean Daily Volume into the Company's Central Delivery Area (CDA) and/or Eastern Delivery Area (EDA). The delivery area must match the area in which consumption will occur.

6. The proportion of TCPL FT capacity that an eligible customer may request to be turned back each year ("percentage turnback") shall not exceed the proportion of the TCPL capacity that Enbridge is entitled to turn back that year. This percentage turnback will be applied to calculate the customer's turnback capacity limit based on the renewal volume of the direct purchase agreement.

7. If the Company is unable to accommodate all or a portion of an eligible customer's request to turnback TCPL FT capacity in the month requested by the customer, the Company will indicate the month(s) when such customer request can be fully satisfied and the costs, if any, associated with accommodating this request. The customer may then advise the Company as to whether or not they wish to proceed with the TCPL FT capacity turnback request.

8. All TCPL FT capacity turnback requests will be treated on an equitable basis.

9. Customers may withdraw their original election given they provide notice to the Company a minimum of one week prior to the deadline specified in the TransCanada tariff for FT contract extension.

10. The percentage turnback of TCPL FT capacity will be applied at the Direct Purchase Agreement level.

11. Written notice to turnback capacity must be received by the Company the earlier of:

    (a) Sixty days prior to the expiry date of the current contract.

    or

    (b) A minimum of one week prior to the deadline specified in TransCanada tariff for FT contract extension.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2007. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates, as the Board Order, EB-2006-0288.

RIDER: B	BUY / SELL SERVICE RIDER

APPLICABILITY:

This rider is applicable to any Applicant who entered into a Gas Purchase Agreement with the Company, prior to April 1, 1999, to sell to the Company a supply of natural gas.

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Base Charge	$50.00	per month
Maximum Charge	$815.00	per month
Account Charge		
New Accounts	$0.50	per month per account
Renewal Accounts	$0.15	per month per account

The above Basic Charge shall be increased up to the maximum charge, by the new account charge for each new account and by the Renewal Account charge for each renewal account in a Direct Purchase Contract.

BUY / SELL PRICE:

In Buy/Sell Arrangements between the Company and an Applicant, the Company shall buy the Applicants gas at the Company's actual FT-WACOG price determined on a monthly basis in the manner approved by the Ontario Energy Board. For Western Buy/Sell arrangements the FT-WACOG price shall be reduced by pipeline transmission costs.

FT FUEL PRICE:

The FT fuel price used to establish the Buy price in Western Buy/Sell arrangements without fuel will be determined monthly based upon the actual FT-WACOG.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2007. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates, as the Board Order, EB-2006-0288.

RIDER: C	GAS COST ADJUSTMENT RIDER

The following adjustment is applicable to all gas sold or delivered during the period January 1, 2007 to December 31, 2007.

Rate Class	Sales Service (¢/m³)	Transportation Service (¢/m³)
Rate 1	0.0000	0.0000
Rate 6	0.0000	0.0000
Rate 9	0.0000	0.0000
Rate 100	0.0000	0.0000
Rate 110	0.0000	0.0000
Rate 115	0.0000	0.0000
Rate 135	0.0000	0.0000
Rate 145	0.0000	0.0000
Rate 170	0.0000	0.0000
Rate 200	0.0000	0.0000

RIDER: E	REVENUE ADJUSTMENT RIDER

The following adjustment shall be applicable to billed volumes during the period April 1, 2007 to December 31, 2007.

Rate Class	Sales Service (¢/m³)	Transportation Service (¢/m³)
Rate 1	0.2688	0.2310
Rate 6	0.0798	0.0185
Rate 9	0.2598	0.2586
Rate 100	(0.1788)	(0.1732)
Rate 110	(0.0327)	(0.0346)
Rate 115	0.0132	0.0117
Rate 135	0.0038	0.0038
Rate 145	(0.1556)	(0.1402)
Rate 170	0.0174	0.0153
Rate 200	0.1244	0.1204
Rate 300	0.0000	(0.0640)

RIDER: F	ATMOSPHERIC PRESSURE FACTORS

The following elevation factors shall be applicable to metered volumes measured by a meter that does not correct for atmospheric pressure.

Zone	Elevation Factor
1	0.9644
2	0.9652
3	0.9669
4	0.9678
5	0.9686
6	0.9703
7	0.9728
8	0.9745
9	0.9762
10	0.9771
11	0.9839
12	0.9847
13	0.9856
14	0.9864
15	0.9873
16	0.9881
17	0.9890
18	0.9898
19	0.9907
20	0.9915
21	0.9932
22	0.9941
23	0.9949
24	0.9958
25	0.9960
26	0.9966
27	0.9975
28	0.9981
29	0.9983
30	0.9992
31	0.9997
32	1.0000
33	1.0017
34	1.0025
35	1.0034
36	1.0051
37	1.0059
38	1.0170

	Rate (excluding GST)
New Account Or Activation	
New Account Charge Turning on of gas, activating appliances, obtaining billing data and establishing an opening meter reading for new customers in premises where gas has been previously supplied	$25.00
Appliance Activation Charge - Commercial Customers Only Commercial customers are charged an appliance activation charge on unlock and red unlock orders, except on the very first unlock and service unlock at a premise.	$65.00 minimum 1/2 hour work. Total Amount depends on time required
Meter Unlock Charge - Seasonal or Pool Heater Seasonal for all other revenue classes, or Pool Heater for residential only	$65.00
Statement of Account	
Lawyer Letter Handling Charge Provide the customer's lawyer with gas bill information.	$15.00
Statement of Account Charge (for one year history)	$10.00
Cheques Returned Non-Negotiable Charge	$20.00
Gas Termination	
Red Lock Charge Locking meter or shutting off service by closing the street shut-off valve (when work can be performed by Field Collector)	$65.00
Removal of Meter Removing meter by Construction & Maintenance crew	$260.00
Cut Off At Main Charge Cutting service off at main by Construction & Maintenance Crew	$1,200.00
Valve Lock Charge Shutting off service by closing the street	
shut-off valve - work performed by Field Investigator	$125.00
- work performed by Construction & Maintenance	$260.00

RIDER: **G**

<u>Safety Inspection</u>

Inspection Not Ready Charge (safety inspection) When a builder requests an unlock and the appliance(s) are not ready for inspection, this charge will apply to cover the cost of returning to the same property for the additional inspection.	$65.00
Inspection Reject Charge (safety inspection) Energy Board Inspection rejects are billed to the meter installer or homeowner.	$65.00

<u>Meter Test</u>

Meter Test Charge When a customer disputes the reading on his/her meter, he/she may request to have the meter tested. This charge will apply if the test result confirms the meter is recording consumption correctly.	
Residential meters	$97.50
Non-Residential meters	Time & Material per Contractor

<u>Street Service Alteration</u>

Street Service Alteration Charge For installation of service line beyond allowable guidelines (for new residential services only)	$32.00

<u>NGV Rental</u>

NGV Rental Cylinder (weighted average)	$12.00

<u>Other Customer Services (ad-hoc request)</u>

Labour Hourly Charge-Out Rate	$130.00
Cut Off At Main Charge - Commercial & Special Requests Cut Off At Main charges for commercial services and other residential services that involve significantly more work than the average will be custom quoted.	custom quoted
Cut Off At Main Charge - Other Customer Requests Other residential Cut Off At Main requests due to demolitions, fires, inactive services, etc. will be charged at the standard COAM rate.	$1,200.00
Meter In-Out (Residential Only)) Relocate the meter from inside to outside per customer request	$260.00
Request For Service Call Information Provide written information of the result of a service call as requested by home owners.	$30.00
Temporary Meter Removal As requested by customers.	$260.00
Damage Meter Charge	$360.00

APPLICABILITY:

This rider is applicable to any Applicant who enters into Gas Transportation Agreement with the Company under any rate.

ENHANCED TITLE TRANSFER SERVICE:

In any Gas Transportation Agreement between the Company and the Applicant, the Applicant may elect to initiate a transfer of natural gas between the Company and another utility, regulated by the Ontario Energy Board, at Dawn for the purposes of reducing an imbalance between the customer's deliveries and consumption within the Enbridge Gas Distribution franchise areas. The ability of the Company to accept such an election may be constrained at various points time for customers obtaining services under any rate other than Rate 125 or 300 due to operational considerations of the Company.

The cost for this service is separated between an Adminstration Charge that is applicable to all Applicants and a Bundled Service Charge that is only applicable to Applicants obtaining services under any rate other than Rate 125 or 300.

Administration Charge:

Base Charge	$50.00	per transaction
Commodity Charge	$1.3115	per 10^3m^3

Bundled Service Charge:
The Bundled Service Charge shall be equal to the absolute difference between the Eastern Zone and Southwest Zone Firm Transportation tolls approved by the National Energy Board for TCPL at a 100% Load Factor.

GAS IN STORAGE TITLE TRANSFER:

An Applicant that holds a contract for storage services under Rate 315 or 316 may elect to initiate a transfer of title to the natural gas currently held in storage between the storage service and another storage service held by the Applicant, or a other Applicant that has contracted with the Company for storage services under Rate 315 or 316. The service will be provided on a firm basis up to the volume of gas that is equivalent to the more restrictive firm withdrawal and injection parameters of the two parties involved in the transfer. Transfer of title at rates above this level may be done on at the Company's discretion.

For Applicants requesting service between two storage service contracts that have like services, each party to the request shall pay an Administration Charge applicable to the request. Services shall be considered to be alike if the injection and deliverability rate at the ratchet levels in effect at the time of the request are the same and both services are firm or both services are interruptible. In addition to like services, the Company, at its sole discretion based on operational conditions, will also allow for the transfer of gas from a storage service contract that has a level of deliverability that is higher than the level of deliverability of the storage service contract the gas is being transfered to with only the Administration Charge being applicable to each party.

In addition to the Administration Charge, Applicants requesting service between two storage service contracts not addressed in the preceding paragraph would be subject to the injection and withdrawal charges specified in their contracts.

Administration Charge:	$25.00	per transaction

Hydro One Networks Inc., For 2007 and 2008 Electricity Transmission Revenue Requirements, Decision with Reasons, EB-2006-0501

Ontario Energy Board

Commission de l'Énergie de l'Ontario

EB-2006-0501

IN THE MATTER OF AN APPLICATION BY

HYDRO ONE NETWORKS INC.

FOR 2007 AND 2008 ELECTRICITY TRANSMISSION REVENUE REQUIREMENTS

DECISION WITH REASONS

August 16, 2007

Summary of the Decision with Reasons
(EB-2006-0501)

Chapter	Application	Board Decision
2	Revenue Requirement Adjustment Mechanism for 2009 and 2010	Not approved.
3	Board's jurisdiction to provide guidance on human resource costs	Board has the authority to make findings and provide guidance on the reasonableness of compensation costs.
4	OM&A expenses	Approved. Data on asset condition to be improved.
	Compensation levels	Approved. Improved reporting required and any reductions in executive compensation to be tracked.
5	Capital expenditure budget	Approved. Data on asset condition to be improved.
	Prudence of Niagara Reinforcement Project	Approved.
6	Special treatment for designated capital projects	Not approved.
	Special treatment of Niagara Reinforcement Project	Applicant allowed to expense carrying costs.
7	Return on Equity	Not approved. Applicant to use the Distribution ROE formula.
	Capital Structure	Same as allowed for electricity distributors.
8	OEB Costs deferral account	Not approved.
	2006 Earnings Sharing Mechanism	Adjustments required to excess income calculation. Capital contribution treatment not allowed.
	2007 Revenue Deficiency Deferral Account	To be effective January 1, 2007.
9	Load forecast	Weather-normal peak load forecast approved. Report required on weather normalization and differences with the IESO forecast.
	CDM impact	Reduced by 350 MW.
10	Charge determinants	Status quo approved.
11	Implementation	Uniform Ontario Transmission Rates to be set in a further proceeding; targeted effective date of change November 1, 2007.

This summary excludes the particulars in the Settlement Proposal and does not form part of the Decision nor does it itemize all findings. It is not to be relied on for the purpose of applying or interpreting the Decision.

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EB-2006-0501

IN THE MATTER OF the *Ontario Energy Board Act,1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the transmission of electricity commencing January 1, 2007.

BEFORE: Pamela Nowina
Vice Chair and Presiding Member

Paul Sommerville
Member

Bill Rupert
Member

DECISION WITH REASONS

August 16, 2007

1. INTRODUCTION

1.1 THE APPLICATION

Hydro One Networks Inc. (“Hydro One”, the “Company”, the “Utility” or the “Applicant”) filed an application dated September 12, 2006 (the “original Application”) with the Ontario Energy Board (the “Board”) under section 78 of the *Ontario Energy Board Act, 1998*; S.O. c.15, (Sched. B) (the “Act”), for an order or orders approving “the revenue requirement for the test years 2007 and 2008; customer rates for the transmission of electricity to be implemented on May 1, 2007; changes to the current capital structure with an increase in the return on common equity; the inclusion into rate base of certain capital costs; a revenue requirement adjustment mechanism for 2009 and 2010”; and other matters related to the fixing of just and reasonable rates for the transmission of electricity. The Board assigned file number EB-2006-0501 to the Application. Updates to certain parts of the original Application were filed on February 23, 2007 (the “updated Application”).

The transmission revenue requirement of Hydro One Networks Inc. (then known as Ontario Hydro Networks Company Inc.) was last set in proceeding RP-1998-0001 when the Board approved a Transitional Rate Order, dated March 31, 1999 and effective April 1, 1999. This revenue requirement was amended to update Hydro One’s Rate of Return on Common Equity on March 1, 2000 (EB-1999-0526). On May 26, 2000 the Board issued its decision on Hydro One’s transmission cost allocation and rate design application (RP-1999-0044).

Appendix 1 contains details regarding the procedural aspects of the Application, including a list of witnesses and a list of active parties.

1.2 THE SETTLEMENT CONFERENCE AND SETTLEMENT PROPOSAL

An Issues List was provided to parties with Procedural Order No. 2 on December 20, 2006. On March 26, 2007 a Settlement Conference was held to settle as many of the issues as possible. The Settlement Conference resulted in a Settlement Proposal which was filed with the Board on April 3, 2007. The Board considered the Settlement Proposal at a hearing held on April 10, 2007. The Board issued its Settlement Proposal Decision on April 18, 2007. The Settlement Proposal and the Settlement Proposal Decision are attached to this decision as Appendices 2 and 3 respectively.

Of the 40 issues on the Issues List, the Settlement Proposal fully settled 24 issues (the “Settled Issues”) and partially settled two issues (“Partially Settled Issues”). The parties were unable to reach agreement on the remaining 14 issues.

Fully Settled Issues

Issue 1.1	Effectiveness and Efficiency of Affiliate Service Agreements
Issue 1.2	Board directions from previous proceedings (some specifics to be addressed part of other issues, principally issues, 9.1, 3.4 and 2.2).
Issue 1.6	Economic and Business Planning Assumptions
Issue 2.3	Cost Allocation between Distribution and Transmission
Issue 2.4	Depreciation Expense
Issue 2.5	Overhead Capitalization Rate
Issue 2.6	Capital and Property Taxes
Issue 2.7	Income Taxes and Methodology
Issue 3.3	Capital and Common Asset Allocation
Issue 3.5	Lead Lag Study for Working Capital Calculation
Issue 3.6	Asset Condition Assessment
Issue 3.7	Allowance for Funds Used During Construction
Issue 5.1	External Revenues
Issue 6.1	Cost Pools and Allocation to the pools
Issue 6.2	Dual Function Lines
Issue 6.3	Wholesale Meter Pool
Issue 6.4	Directly Connected Customers and Line Connection Charges
Issue 6.5	Cost Pools and Local Loop allocation
Issue 7.2	Forecast for Charge Determinants
Issue 7.4	Continuation of the Export Transmission Tariff
Issue 8.1	Deferral and Variance Accounts (establishment and methodology)
Issue 8.2	Deferral and Variance Accounts (amounts and disposition)

Issue 8.3 Service Levels and Performance Standards
Issue 8.4 Demonstration of Need for Leaside/Birch Junction project

Partially Settled Issues

Issue 3.1 Rate Base
Issue 7.3 Charge Determinants for Network and Connection Service

Settlement Proposal Decision

The Board accepted the Settlement Proposal on April 10, 2007 save for the three issues below, which were addressed in its Settlement Proposal Decision of April 18, 2007:

Issue 7.4	The Board modified the language for the settlement of the Export Transmission Rates issue.
Issue 8.4	The Board did not accept the Settlement Proposal and directed Hydro One to present evidence on the need to relieve loading on the connection lines between Leaside TS and Birch Junction TS in the oral hearing.
Issues 8.1 & 8.2	The settlement of the Ontario Energy Board Cost Account was not accepted by the Board.

This Decision with Reasons addresses the 14 non-settled issues, beginning at Chapter 2.

1.3 PARTIAL DECISION AND ORDER

In a letter dated February 14, 2007 Hydro One requested that a 2007 revenue deficiency deferral account be established, beginning January 1, 2007, to record the revenue deficiency between the approved revenue for 2007 and the forecast revenues at currently approved transmission rates. Hydro One requested a decision from the Board on this issue by March 31, 2007. On March 30, 2007, the Board issued a Partial Decision and Order approving the establishment of the 2007 revenue deficiency deferral account. The Partial Decision and Order is attached as Appendix 4. Further details regarding this account are found in Chapter 8 of this decision.

1.4 UNIFORM TRANSMISSION RATES

In this decision, the Board is approving the revenue requirements and charge determinants for Hydro One Transmission which will form the basis for the Hydro One Networks' portion of the Ontario Uniform Transmission Rates. The Ontario Uniform Transmission Rates and the revenue shares of each of the other transmitters in the transmission rates pool (Great Lakes Power Inc., Five Nations Energy Inc., and Canadian Niagara Power Inc.) will be established in a subsequent proceeding.

1.5 THE HEARING, SUBMISSIONS AND EXHIBITS

The hearing took place at the Board hearing room in Toronto on April 23, 24, 26 and May 7, 8, 11, 14, 15, 17, 18, 22, 28 and June 13, 2007. Copies of the evidence, exhibits, arguments, and transcripts of the proceeding are available for review at the Board's offices.

2. PROPOSED REVENUE REQUIREMENT ADJUSTMENT MECHANISM

Hydro One's Proposal

In addition to an order from the Board approving the revenue requirement for test years 2007 and 2008, Hydro One sought approval for a Revenue Requirement Adjustment Mechanism (RRAM) to set transmission revenues for 2009 and 2010 and to replace a full cost-of-service proceeding for those years.

Hydro One described its RRAM for 2009 and 2010 as an indexed revenue requirement plan that is an extension of the 2008 rate setting process. Each of the components of the company's revenue requirement for 2009 and 2010 – operating, maintenance and administration (OM&A) expenses; depreciation; capital taxes; income taxes; and return on capital – would be recomputed prior to each year and submitted to the Board for approval. The Company submitted that its RRAM process would require a much smaller commitment of resources, time and cost than would a full cost-of-service proceeding.

The most significant aspects of the proposed RRAM are the mechanisms used to compute OM&A expenses and the capital expenditures to be included in rate base. Hydro One's approach to these items (set out in its prefiled evidence, and modified by the testimony of its witnesses) is summarized in Table 1. The table deals only with the 2009 calculations but similar calculations would be done for 2010.

Hydro One proposed that the return on capital in 2009 and 2010 would be based upon the debt-equity ratio and cost of debt approved for 2008. The allowed return on equity would be calculated using the OEB-approved return on equity (ROE) formula for 2008, updated for the then current long Canada bond yield. Depreciation expense and taxes for 2009 and 2010 would be simple recalculations based on the updated expense, rate base, and return on capital.

Table 1: Calculation of 2009 Revenue Requirement/Rate Base Amounts Under Proposed RRAM

Expense/capital addition	Calculation of 2009 Amounts
OM&A expenses	(2008 approved OM&A) multiplied by (1 + inflation factor – productivity factor + "OM&A asset aging" adjustment factor)
Sustaining, Operations, and Shared Services capital expenditures added to rate base	(2008 approved Sustaining, Operations, and Shared Services capital expenditures) multiplied by (1 + inflation factor – productivity factor + "capital asset aging" adjustment factor)
Non-IPSP Development capital expenditures added to rate base	Forecast capital expenditures on projects expected to be in service in 2009 *
IPSP Development capital expenditures added to rate base	Forecast capital expenditures on projects expected to be in service in 2009 *
"Supply mix" capital expenditures added to rate base	Forecast capital expenditures expected to be incurred in 2009 (without regard to the in-service dates of the assets) *

**The amounts added to rate base would be subject to a half-year rule.*

Hydro One submitted that the review and approval process for an adjusted revenue requirement for 2009 could commence in June 2008 and could involve at least two rounds of interrogatories and workshops with intervenors. A negotiated settlement would be presented to the Board for approval. While intervenors strongly opposed the proposal, Hydro One said it believes such a process is achievable based on the experience of the British Columbia Utilities Commission, which has used a similar approach in regulating FortisBC .

Dr. Poray of Hydro One stated that the Company was not seeking to have all the details of its proposed plan approved by the Board in this proceeding. Hydro One, he said, would be "willing to work with the intervenors to try and sort out the details, but I think Hydro One would like the assurance of having a concept approved by the Board as a mechanism for moving forward, where the details would be subject to a review, but it would be a review which is much more streamlined than a full cost of service.” [1] During his examination-in-chief, Dr. Poray listed the specific approvals that Hydro One was requesting as part of this proceeding:

> First of all, we want the Board to approve the concept behind the revenue adjustment mechanism, that is to say the mechanical adjustment mechanism that uses inflation, productivity and asset-aging adjustment factors to calculate the respective increments in OM&A and capital cost components for 2009 and 2010, starting from Board-approved values.
>
> Secondly, we want the Board to approve the concept behind the derivation of the asset-aging factors, which is based on Board-approved information that Hydro One filed as part of the current proceeding.
>
> Thirdly, we want the Board to approve the setting of a constant productivity factor at one percent for the 2009 and 2010 period.
>
> Fourth, we would want the Board to approve the treatment of capital development costs as we’ve outlined previously.”[2]

Hydro One was clear that its RRAM proposal is not a comprehensive incentive regulation plan. In its pre-filed evidence, the Company noted:

> It will not be realistic to design an effective comprehensive incentive regulation regime before that time [2010] for a number of reasons. Most importantly, the industry is currently going through a period of significant uncertainty. This includes structural changes for the industry as well as uncertainty related to supply mix options and timing. Stability will not be achieved until the OPA’s IPSP [Ontario Power Authority’s Integrated Power System Plan] is filed and approved by the OEB and until significant progress is made in implementation planning. In addition, it will be necessary to collect appropriate cost data for several years so that cost functions can be estimated as a basis for setting the cost and

[1] Tr. Vol. 6, p.36

[2] Tr. Vol. 5, p.107 (Dr. Poray is referring to a previous discussion recorded in Volume 5 of the transcript, pages 92 to 99, where he outlines the treatment of capital expenditures in the proposed adjustment mechanism.)

quality parameters for the incentive regulation model that is ultimately adopted as was the case in other jurisdictions[3].

The principal argument made by Hydro One for its RRAM proposal is that it will streamline the approval process during two years that Hydro One expects to have a heavy workload in connection with its capital programs and asset sustainment activities.[4] Other reasons cited by Hydro One were:

- The base year for the adjustment mechanism, 2008, will have been subject to a full cost-of-service review.
- The costs borne by customers for additional operating and capital spending on Hydro One's aging infrastructure will be limited by the pre-approved OM&A and capital adjustment mechanisms.
- The two-year RRAM period will be followed by a full cost-of-service review.
- The two-year RRAM period will allow Hydro One to align subsequent transmission and distribution rate filings.
- The RRAM will reduce the uncertainty with respect to the cost borne by transmission customers in 2009 and 2010, while providing an incentive for Hydro One to contain cost within the envelope established by the adjustment mechanism.
- The RRAM may serve as a first step towards a more comprehensive incentive regulation plan as part of Hydro One's cost-of-service filings for post-2010 rates[5].

[3]Ex.A/Tab13/Sch.1/p.9

[4]Tr. Vol. 5, p. 111

[5] Ex.A/Tab13/Sch1/pp.2-3.

Intervenor Arguments

The RRAM proposal was severely criticized by each of the five consumer groups that participated in the hearing (Association of Major Power Consumers in Ontario "AMPCO"; Consumers' Council of Canada "CCC"; Energy Probe; Schools Energy Coalition "SEC"; and Vulnerable Energy Consumers' Coalition "VECC"). No other intervenors dealt with the RRAM proposal in their arguments. The five consumer groups submitted that the Board should reject Hydro One's proposal and, instead, should require Hydro One to file a full cost-of-service application in respect of 2009 and 2010.

In summary, the intervenors argued that:

- RRAM is only a concept; one that Hydro One acknowledges requires further definition and stakeholdering. The Board should not consider approving an ill-defined proposal.

- It is premature for the Board to approve any automatic revenue requirement adjustment mechanism given the significant uncertainties about the nature and extent of Hydro One's future costs and activities. It was submitted that automatic rate adjustment mechanisms work best when a utility operates in a relatively steady-state environment, which Hydro One admits is not the case today in its transmission business. Some intervenors also submitted that a period of instability and uncertainty is precisely the time when regulatory oversight should be maintained, not relaxed.

- The proposed method of calculating revenue requirement adjustments is flawed. Intervenors raised several issues but were especially critical of the proposed use, and method of calculation, of the OM&A and capital asset aging factors. Intervenors noted that the proposed aging factors were the result of a simple calculation based on the change in spending between 2003 and 2008; no evidence was provided to link the change in spending with asset aging. They also noted that the proposed productivity factor was developed by Hydro One and is not based on external benchmarks.

Board Findings

The Board has been supportive of regulatory mechanisms that provide greater regulatory predictability, reduce regulatory burden, and offer appropriate incentives to regulated utilities. This is clearly demonstrated by the Board's multi-year rate-setting plan for electricity distributors and its current initiative on multi-year incentive regulation for natural gas utilities.

A multi-year revenue requirement adjustment mechanism for electricity transmission may ultimately be appropriate for Hydro One; however, the Board cannot accept the RRAM proposed by Hydro One.

This proceeding is the first cost-of-service review of Hydro One's transmission revenue requirement since 2000. Hydro One pointed out on many occasions that its transmission business today is facing significant change in its spending levels and work programs. During the hearing, Hydro One stressed what it described as an unprecedented increase in capital expenditures driven by government directives and system growth. Hydro One's evidence and its witnesses also referred at length to the significant increase in spending related to Hydro One's aging asset base. The Board also heard evidence about the possible impact of the OPA's IPSP, which has not yet been filed with the Board, on Hydro One's investment plans and spending.

Given these significant changes and uncertainties, the Board does not believe that this is the time to adopt a revenue requirement adjustment mechanism for 2009 and 2010. Before setting the post-2008 revenue requirement, it will be important to examine how actual OM&A expenses and capital expenditures in 2007 and 2008 compare with Hydro One's forecasts (and to determine the reasons for any significant variations), and to test forecasts of spending in subsequent years. That can only be accomplished through a cost-of-service proceeding.

Even if the environment were more stable, the Board would be unable to accept the proposed RRAM because it is not a fully developed plan. The Board does not see how it could approve a mechanism in concept when many of the elements of the mechanism are not clearly defined or are open to change based on future consultations. While the Board appreciates that Hydro One is willing to consult with stakeholders on various aspects of its proposal, it believes that consultation should occur prior to a proposal being submitted to the Board in a rates case.

The Board also shares the intervenors' concerns about some aspects of the proposed indexing of OM&A and certain capital expenditures, especially the use and calculation of the proposed asset aging factors. In its evidence, Hydro One stated that the residual growth in OM&A spending from 2003 to 2008 was "deemed to represent the effect of asset aging on OM&A costs."[6] Should Hydro One choose to submit a multi-year adjustment mechanism that contains asset aging factors as part of its next transmission rates case, the Board will expect detailed evidence to establish that such factors are appropriate estimates of the increase in costs due to asset aging. The Board also expects that any productivity factors will be supported by detailed information and external comparisons.

The Board does not accept Hydro One's proposed Revenue Requirement Adjustment Mechanism for 2009 and 2010. The revenue requirement for those years should be established through a full cost-of-service proceeding. Multi-year incentive regulation for Hydro One Transmission could be implemented in subsequent years.

[6] Ex.A/Tab13/Sch1/p.14

3. JURISDICTION

The Society of Energy Professionals (the "Society") has challenged the Board's jurisdiction to provide detailed guidance to Hydro One with respect to compensation costs negotiated as part of the collective bargaining process with its various unions. In its written submissions it stated:

> It is the position of the Society that the statutory jurisdiction of the Ontario Energy Board to set rates for the transmission of electricity does not include the jurisdiction to:
>
> 1. Issue directions or orders which would in effect require Hydro One to violate the terms of a binding collective agreement with any of the unions representing Hydro One employees;
> 2. Issue directions or orders regarding positions Hydro One must take or objectives it must pursue in collective bargaining with unions representing Hydro One employees;
> 3. Issue directions or orders which in any other way would have the effect of pre-empting free and good faith collective bargaining between Hydro One and the unions representing Hydro One employees.

The Board notes that the Society did not challenge a specific decision of the Board. Rather, the Society appears to be anticipating reasons from the Board similar to those issued in Hydro One's 2006 Distribution Rates Decision (RP-2005-0020/EB-2005-0378), the "Distribution decision"; in particular, certain paragraphs which state clearly the Board's concerns with the Company's labour rates and compensation costs. In its Distribution decision the Board said:

> 3.4.3 The Board notes that the high compensation issue for Hydro One has a considerable history before this Board, dating back to the Ontario Hydro days.

> The Board has noted in this proceeding that since the de-merger of Ontario Hydro, Hydro One has taken a number of steps to control its overall compensation costs by, for example, instituting a voluntary retirement program, outsourcing, use of the PWU hiring hall, initiating various cost efficiency programs, holding the line on compensation increases for management employees and imposing a two-tiered pension structure or a pension plan that is less generous for new employees represented by the Society of Energy Professionals. These are positive steps and the Board expects the company to continue and enhance such efforts in the future and report to the Board at the next main rates case. The Board is particularly concerned about the apparently high labour rates. In this respect, the Board expects Hydro One to identify what steps the company has taken or will take to reduce labour rates.
>
> 3.4.4 Even so, the comparisons between Hydro One's cash compensation with certain other utilities presented by intervenors are of concern. For example, SEC calculated that by applying Ottawa Hydro's compensation costs to Hydro One employees there would a reduction of about $85 million in Hydro One's cash compensation. The Board recognizes that there may be some roughness in the derivation of that figure and some differences in the profile of the two utilities. However the contrast between the compensation structures is of concern to the Board.
>
> 3.4.5 The Board will not make an adjustment to the proposed OM&A costs based on compensation levels at this time but expects the utility to demonstrate in the future that lower compensation costs per employee have been achieved or demonstrate concrete initiatives whereby compensation costs will be brought more in line with other utilities.

In the Society's view, such directions are beyond the jurisdiction of this Board as they interfere with and have the effect of frustrating the statutorily mandated collective bargaining process at the utility.

The Society also contended that in so far as the Board appears to mandate reductions in labour rates or compensation costs, it has assumed a direct role in the negotiation process which is improper and inconsistent with the collective bargaining process. It suggests that in such circumstances, the Board has become "the ghost at the bargaining table" imposing limits on the scope of negotiation without any direct accountability to others participating in the process.

While it appears to find the Board's comments in the Distribution decision to be problematic, the Society did not seek a review of that decision, either at the Board or elsewhere. A consideration of jurisdictional issues is best undertaken when a specific action or decision by the tribunal is considered by a party to fall outside its jurisdiction. Dealing with jurisdictional issues on a speculative or theoretical basis is awkward, and not particularly useful.

If the Society regards some aspects of this Decision to be outside the Board's jurisdiction, it has a range of remedies available to it where its concerns can be addressed and adjudicated. Nonetheless, it may be helpful and appropriate to address some of the issues raised by the Society now.

The scope of the Board's jurisdiction is always subject to its own assessment in light of specific challenges, and, ultimately, when invoked by a party, to that of the Court.

The Board's jurisdiction with respect to ratemaking has been the subject of considerable recent examination by the Board itself and by the courts. While most of that commentary has concerned the process for establishing gas distribution rates, it is clear that the Legislature has endowed the Board with broad powers in the establishment of just and reasonable rates for electricity transmission as well. The Board's jurisdiction derives from the following sections of the Act:

> 19(1) The Board has in all matters within its jurisdiction authority to hear and determine all questions of law and fact.
>
> 19(6) The Board has exclusive jurisdiction in all cases and in respect of all matters in which jurisdiction is conferred on it by this or any other Act.
>
> 78(1) No transmitter shall charge for the transmission of electricity except in accordance with an order of the Board, which is not bound by the terms of any contract.
>
> 78(3) The Board may make orders approving or fixing just and reasonable rates for the transmitting or distributing of electricity and for the retailing of electricity in

> order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998*.
>
> 78(7) Upon an application for an order approving or fixing rates, the Board may, if it is not satisfied that the rates applied for are just and reasonable, fix such other rates as it finds to be just and reasonable.
>
> 78(8) Subject to subsection (9), in an application made under this section, the burden of proof is on the applicant.
>
> 78(9) If the Board of its own motion, or upon the request of the Minister, commences a proceeding to determine whether any of the rates that the Board may approve or fix under this section are just and reasonable, the Board shall make an order under subsection (3) and the burden of establishing that the rates are just and reasonable is on the transmitter or distributor, as the case may be.
>
> 128(1) In the event of conflict between this Act and any other general or special Act, this Act prevails.

In addition, when carrying out its responsibilities under the Act, the Board is subject to explicit objectives to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service; to promote economic efficiency and cost effectiveness in the transmission of electricity; and to facilitate the maintenance of a financially viable electricity industry.

In assessing the Society's assertions it is important to note that where there is jurisdiction to regulate there is also an obligation to regulate. A regulatory body such as the Board has a positive obligation to fulfill the mandate bestowed upon it by the Legislature.

The Board has a positive obligation pursuant to section 78 to ensure that the rates governing the transmission of electricity are just and reasonable. In a decision that has been relied upon and cited numerous times, the Supreme Court of Canada has held that just and reasonable rates are those which strike an appropriate balance between the interests of consumers on one hand, and the right of the utility to make a reasonable return on its investment, on the other.[7]

A number of intervenors argued, and Board staff observed, that the Board's method of determining just and reasonable rates does not include prohibiting the subject utility from making expenditures or incurring costs at rigidly prescribed levels. Rather, the Board approves a revenue requirement that is consistent with its findings on various cost categories, including operating costs. The courts have recognized that operating costs include compensation costs[8], and that in the course of setting just and reasonable rates, numerous costs may be subject to challenge including those related to compensation plans[9].

The Board's obligation to arrive at just and reasonable rates, and to protect the interests of consumers, requires it to assess the reasonableness of all cost categories for which recovery is sought. The Board has a wide discretion to allow, disallow or adjust the components of both rate base and expense[10].

In the Distribution decision, the Utility's labour rates and compensation costs appeared consistently higher than those of comparable North American utilities. As a result, the Board panel deciding the Distribution case asked the Utility to identify steps it had taken or would take to reduce labour rates in the next Distribution rates case filing. The panel also required the Utility "to demonstrate in the future that lower compensation costs per employee have been achieved or demonstrate concrete initiatives whereby compensation costs will be brought more in line with other utilities".

[7] "Just and reasonable" rates have been defined by the courts as those which are fair to the consumer and which permit the company to earn a fair return on the capital invested: *Northwestern Utilities, Ltd.* v. *City of Edmonton et al*., [1929] S.C.R. 186, cited in *Re Union Gas Ltd.* v. *Ontario Energy Board et al*. (1983) 1 D.L.R. (4th) 698 (Ont. H.C.J.), p. 706.

[8] *Re Union Gas Ltd. v. Ontario Energy Board et. al*., ibid., p. 702.

[9] *Transcanada Pipelines Ltd*. v. *Canada (National Energy Board)* [2004] F.C.J. No. 654. (C.A.), para. 34.

[10] *Re Union Gas Ltd. v. Ontario Energy Board et al*., *supra.*, p. 712.

That panel also required the Utility to provide further detailed information respecting the full extent of what appeared to be a disparity in comparative compensation costs. The underlying rationale for this finding was to ensure that the costs incurred by the Utility with respect to labour rates and compensation costs are reasonable, and can therefore form the basis of part of the overall revenue requirement of the Utility.

The same approach is taken for all other categories of costs that comprise a utility's revenue requirement. In making the finding that it did in the Distribution case, the Board was giving the Utility fair warning that the Board had concerns about the apparent disparity in comparative labour rates and compensation costs.

The Board did not and does not prohibit the Utility from paying to its workforce whatever it negotiates within the context of its labour relations environment. What the Board does do is limit the recovery as part of the revenue requirement to that portion of compensation cost which the Board finds to be reasonable.

In other words, the Utility is free within the negotiating environment to arrive at whatever resolution it sees fit. It has to do so, however, with knowledge that full recovery of the consequential cost may not be available to the extent that the Board considers the settlement to be unreasonable.

To do otherwise would make the ratepayers captive to whatever private arrangements are agreed to by the Utility and its unions. The Board can only meet its responsibility to protect the interests of consumers if it assesses the reasonableness of the costs which result from such settlements and provides for recovery according to a fair, transparent, and principled regulatory approach.

In its Reply submission, the Society argued that the Board has no authority to make orders which have the effect of compelling the Utility to violate labour relations agreements to which it is bound.

It is not the practice of this Board to make any such orders. The Board is expressly not bound by the terms of any contract in its establishment of just and reasonable rates pursuant to Section 78 of the Act. The Board assesses the reasonableness of the cost consequences of the utility's arrangements, and establishes the revenue requirement on the basis of that assessment. The Board's view of the reasonableness of compensation costs is just one of the factors that the parties at the bargaining table must take into account. The consequence of a Board finding that this category of cost is excessive is a possible disallowance of a portion of the amount claimed by the utility for inclusion in the revenue requirement. In that hypothetical case, the utility would decide whether to attempt to change its compensation practices or to source the additional funding from the shareholder.

Accordingly, the Board finds that it has the authority to make findings and to provide guidance with respect to the reasonableness of a utility's compensation costs for the purpose of setting just and reasonable rates for utility service.

4. OPERATIONS, MAINTENANCE AND ADMINISTRATION

This chapter contains the Board's findings on Hydro One's proposed Operations, Maintenance and Administration expenses (OM&A) as well as the level of the Company's compensation costs.

4.1 OM&A EXPENSES

Hydro One's updated evidence showed a forecast for OM&A expenses of $394.1 million for the 2007 test year with a slight decrease to $387.5 million in the 2008 test year. The 5.1% increase for 2007 was in addition to an increase of almost 10% in the 2006 bridge year. Table 2 shows Hydro One's forecast amounts compared with those in the preceding four years.

Table 2: OM&A Expenses 2003 – 2008

	Historic			Bridge	Test	
$ millions	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
OM&A by category						
Sustaining	$146.9	$153.9	$166.3	$179.0	$200.1	$200.9
Development	2.2	5.0	6.7	8.1	8.0	8.1
Operations	36.6	49.5	38.3	42.9	45.8	46.2
Shared services and other	125.8	81.9	59.9	76.3	67.4	57.1
Taxes, other than income taxes	55.4	68.1	70.5	68.6	72.8	75.1
Total OM&A	$366.8	$358.4	$341.8	$374.8	$394.1	$387.5
Year over year % change						
Sustaining OM&A		4.8%	8.1%	7.6%	11.8%	0.4%
Total OM&A		-2.3%	-4.6%	9.7%	5.1%	-1.7%

This part of the hearing focused mainly on Sustaining OM&A expenditures as this category represents just over half of the OM&A total. The Sustaining OM&A budget represents spending required to maintain existing transmission lines and station facilities so they will continue to function as originally designed and meet overall system reliability, environmental and safety requirements.

One reason for intervenor interest in the Sustaining category is the fact that it has had consistent increases in expenditures from 2003 through to the test years. Sustaining spending in 2007 is forecast to be almost 12% higher than in 2006, a year in which spending rose by 7.6% over 2005 levels.

Hydro One defended its Sustaining OM&A expenditure plans on the basis of its business planning process where it uses leading measures related to the performance, condition and age of the specific assets which make up the transmission system. The information supporting Hydro One's plans include asset performance (asset failure rate) studies, asset condition assessments and asset demographics information.

The asset demographic information identified the number of assets which are expected to enter specific critical age regions, such as mid-life, where incremental maintenance requirements are necessary to ensure continued asset performance, and end-of-life where it becomes uneconomic to try to sustain the required performance levels. Hydro One emphasized that both the volume and scope of OM&A work is increasing for Hydro One's aging fleet of assets. It is the Company's position that the business planning process utilized by Hydro One has established the appropriate level of sustaining work, based on a detailed needs identification and work program prioritization[11].

VECC highlighted that in Hydro One's original application, Sustaining OM&A expenditures were increasing by 28% from $155.9 million in 2006 to $200.1 million in

[11] Ex.A/Tab14/Sch1

2007. In the evidence update, the Sustaining OM&A spending for 2006 was revised upwards to $179.0 million.

Hydro One’s explanation for the higher than expected spending in 2006 was that higher than anticipated failure rates were experienced that year, associated with a specific transformer design and storms. Unexpected difficulty in getting cleanup crews to the affected sites increased unanticipated expenses Hydro One testified that this higher 2006 spending does not impact on spending plans for 2007 and 2008.

VECC did not accept Hydro One’s assertion that assets and performance were actually deteriorating. VECC noted that as the updated information provided by Hydro One showed that outages of 230kV circuit breakers were lower in 2006 than in any of the previous three years, and that outages of 230 kV transformers were well below 2005 levels and in line with those in 2003 and 2004.

VECC also argued that the 2006 asset condition assessment did not show a marked difference in overall condition of the transmission assets and did not substantiate the requested increase in OM&A Sustaining spending.

VECC also noted that Hydro One’s evidence indicated that a significant portion of the Priority 1 (“very poor”) and Priority 2 (“poor”) assets will actually be replaced over the 2006-2008 period. VECC submitted that if this level of replacement proceeds, it will have a direct impact on the level of Sustaining OM&A spending needed for these assets and should reduce overall maintenance requirements. VECC also noted that in the High Level Transmission Benchmarking Study prepared by the PA Consulting Group (September 6, 2006), [12] Hydro One Networks OM&A spending was close to the average for those utilities surveyed when normalized on either a total Gross Asset Basis or a MWh transmitted basis using data from 2003-2005. Similarly, Hydro One’s reliability was shown to be about average. VECC held that this evidence showed that current levels of spending were reasonably adequate.

[12] Ex.A/Tab15/Sch2

In conclusion, VECC submitted that the proposed Sustaining OM&A budgets be reduced by 6% in both test years to $188.1 million in 2007 and $188.8 million in 2008.

AMPCO questioned whether the evidence established that assets are aging at a specific rate, or a rate greater or lesser than in the past, or that asset aging is creating a significant deterioration in reliability. AMPCO urged the Board to direct Hydro One to provide clear evidence on asset aging at its next rate hearing.

Citing evidence which appeared to show that the 2006 outage performance was better than previously indicated, AMPCO argued that Hydro One’s data did not support a claim of significant and increasing problems with asset performance.

AMPCO maintained that Canadian Electrical Association data did not indicate a significant deterioration in system performance over the period 2003 to 2006. In addition, Hydro One’s evidence showed that the Company achieved first quartile system performance compared to American utilities over the five-year period from 2000 to 2005.

AMPCO also submitted that the higher proposed capital spending should reduce the need for additional sustainment OM&A spending in future years.

Based on the above, AMPCO submitted that the 2007 Sustaining budget should be reduced to $185 million, and the 2008 budget to $195 million. AMPCO noted that Hydro One’s proposals for Development, Operations, Shared Services and Other OM&A appeared reasonable.

CCC supported the AMPCO analysis of asset aging, asset condition and asset performance. CCC was also concerned about the increased bridge year spending revealed in the update, with no reduction shown in 2007 and 2008 plans. CCC recommended Sustaining OM&A spending be reduced by $10 million to $190.1 million in 2007.

SEC also submitted that planned Sustaining OM&A increases were too high in the test years. SEC argued that expenditure increases should have taken place earlier, citing evidence from Hydro One's 1999 transmission rates proceeding which indicated Hydro One was already aware that blocks of assets were reaching the end of their service lives.

SEC argued a prudent company, operating in a competitive market, which foresaw an imminent need to refurbish or replace aging assets would not wait until all of those assets reached a certain age before taking action. Rather, it would seek to smooth the impact of those investments to avoid problems with cash flow in a given year.

SEC also referred to the improvement in asset failure rates and forced outages in 2006, as shown in the updated evidence. SEC focused on Exhibit L1.3 where comparisons of OM&A per line kilometre show a 12% increase from 2006 to 2007 compared to an average annual increase between 2003 and 2006 of only 7%. SEC recommended that the Sustaining OM&A budget should be frozen at the updated 2006 level of $179 million for each of 2007 and 2008. This would mean a reduction in the OM&A budget of $21.1 million in 2007, and $21.9 million in 2008. SEC's rationale for the reduction is based on its view that although planned expenditures in 2007 and 2008 are needed, they are unreasonable for inclusion in 2007 and 2008 rates because they are the result of imprudently low expenditures in the historic years. It contends that the Company should have been investing in the business during a period of overearning, and should not make up for that failure during the test years. SEC also asserts that the proposed spending levels do not take into account the higher 2006 spending levels revealed in the evidence update in February. In its view, this higher spending in 2006 should result in lower spending in the test years.

The Power Workers' Union ("PWU") supported the levels of OM&A spending applied for by Hydro One on the basis that Hydro One demonstrated the need for the levels of spending through their planning methods (asset condition assessment, outage data and asset aging data). PWU argued that if the Board found that these planning methods are reasonable, then the results should be accepted as well. PWU submitted that as more units of work are required, and wages and material costs are increasing also, the increased costs are justified. PWU also submitted that if reductions are ordered, the impact of not doing this work on service quality, reliability and safety must also be taken into account.

Board Findings

Hydro One is seeking approval of a significant increase in its Sustaining OM&A spending. The key issue is the need for planned spending in 2007 which is almost 30% higher than the $155.9 million originally planned for 2006.

The primary concern of intervenors with respect to this increase is its magnitude when compared to spending in this area in the recent past. Hydro One's response was that the need for such increases became apparent recently, and as the result of improved analytical and planning techniques. It argues that it would not have been prudent to make larger investments in preceding years, given its understanding of the condition of its plant at that time.

It is the view of the consumer intervenors that such large program increases require strong and objective evidence of a broadly-based deterioration in system performance or a demonstrated severe and rapid deterioration of a major asset class. They argue that no such evidence has been provided by Hydro One.

Intervenors suggest that it is impossible to conclude from the evidence provided by Hydro One that its asset base is aging at any specific rate, that this rate is greater or less than it has been in the past, or that further asset aging is creating a significant deterioration in reliability. Intervenors also assert that the evidence does not support claims of significant and increasing problems with Hydro One's assets or system performance deterioration.

Hydro One answers that the use of historic data to extrapolate an appropriate spending level for the test year is unsound. It argues that transmission system reliability is a lag indicator – by the time impairments in reliability become apparent it is too late. The Company relies on an improved package of leading indicators to plan its expenditures in this category.

The Company also asserts that while the evidence shows there was a marginal decrease in the failure rate of a single asset class in 2006, the trend is that of increasing and continuing deterioration overall.

The Company also disputes the claim made by some of the intervenors that the 2003/2006 Asset Condition Assessment comparison does not show asset condition deterioration. It suggests that the comparison made by the intervenors is inappropriate, given that it is based on two materially different data bases. The Company also separates its significant increases in capital expenditures to replace assets from its OM&A budget. It argues that there is no good reason to conclude that the replacement program contemplated will have any material effect on the short-term OM&A requirements.

The Board notes that the concerns of the intervenors with respect to the proposed level of spending were heightened by Hydro One's request that the Board approve a RRAM for 2009 and 2010. Under the proposed RRAM, the approved OM&A spending for 2008 would find its way into a rate adjustment mechanism for the following years. As noted in Chapter 2, the Board has not approved Hydro One's request for the RRAM, and the revenue requirement for 2009 will be based on a cost-of-service examination.

In the OM&A section of the Application, as in a number of other sections, the Board found some of the evidentiary record to be inadequate or incomplete. For example and as noted above, the Applicant insisted that the overall trend of its assets was continued and increasing deterioration while the evidence it placed before the Board on that point showed a marginal decrease in the failure of a single asset class in 2006. The Board has concerns about the comparatively low spending levels in the years preceding the bridge year. It would be expected that a large and capable transmission company, such as the Applicant, would have had a more reliable asset condition assessment capability than appears to have been the case until recently. The Board would expect that the Company would attempt to smooth spending on this category of expense as much as possible, given the nature of the activity, which is, by definition, incremental in nature. It is concerning that the revenue requirement would include such a steep increase from one year to the next. While the Company has provided an explanation for its request for the sharp increase sought there remains ambiguity about the real state of the asset base. The evidence presented by the Company is not always consistent with the claims advanced.

It would have been better had the Company had been able to demonstrate with more acuity the statistical and technical underpinning of its point of view. The safe and reliable operation of the system is of paramount importance to the province’s economy, and the well being of its population. This Application, and many other matters currently before the Board, documents the fact that the transmitter is engaged in very significant extensions and reinforcements of the system.

In the Board’s view, resolving the ambiguity of the asset reliability evidence against the applicant by reducing the proposed OM&A budget would be inappropriate and unsafe. The Board is convinced that the Company has genuinely formed the judgment, based on its engineering expertise and its enhanced analytical capability, that increases of the nature applied for are needed to maintain a robust, safe, and reliable transmission system.

Accordingly, the Board will approve the OM&A budget as applied for the years 2007 and 2008. However, the Board directs the Applicant to work with intervenors to develop the type of and format for data reflecting asset condition. In particular, the Board directs Hydro One to provide asset aging data which includes data by value and importance of the type of asset, as suggested in AMPCO's submissions, in its next transmission rates proceeding.

It is important that an approach is found that will allow all parties to make better assessments of the state of the asset base at the time of the next revenue requirement case. This data must enable the Company to bring to its next cost of service application a reliable representation of all important parameters of the condition and reliability of the asset base and the financial implications thereof. The Applicant will report to the Board no later than six months from the date of this decision on the progress made in the development of its improved asset database. It is the Board's intention that this stakeholdered exercise be implemented in time to provide a very clear representation of the condition of the Company's plant in time for its expected cost of service application for the 2009 revenue requirement.

4.2 EMPLOYEE COMPENSATION

Several intervenors directed their arguments to the overall size and growth of Hydro One's employee compensation cost. These issues are covered in this section. Some intervenors also raised issues with respect to two narrower compensation issues. Those issues are the rate treatment of incentive pay, and the possible impact on senior management compensation of the recommendations of the Province of Ontario's Agency Review Panel. Those two smaller issues are covered at the end of this chapter in section 4.3.

Hydro One conducts both its transmission and distribution businesses within a single corporate entity, Hydro One Networks Inc. Table 3 provides summary information on combined compensation cost and headcount for Hydro One's transmission <u>and</u> distribution businesses for the past four years, and the proposed amounts for 2007 and 2008.

Table 3: Employee Headcount and Compensation (total Hydro One Networks)

	Historic			*Bridge*	*Test*	
Compensation cost in $ millions	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
No. of employees at year end						
Regular	3,696	3,841	3,904	4,018	4,204	4,158
Non-regular	906	1,032	1,174	1,283	1,605	1,645
Total	4,602	4,873	5,078	5,301	5,809	5,803
Compensation cost *	$388.1	$404.2	$397.9	$459.3	$493.0	$508.0

* Includes base salary, overtime pay, incentive pay, benefits (other than costs for pensions and other post-employment benefits), and other compensation.

Source: Exhibit J1.40

A portion of Hydro One's compensation cost is included in OM&A expenses and the balance is included in the cost of various capital projects. Hydro One did not file any information in this proceeding about the amount of total forecast corporate compensation cost for 2007 and 2008 that will be borne by the transmission business (either as OM&A expenses for 2007 and 2008 or as additions to the transmission business rate base). The Company did estimate that just under 50% of full-time equivalent employees for the test year 2008 would be allocated to the transmission business based on the split of work programs between transmission and distribution.

The Board considered compensation issues at Hydro One most recently in its hearing on 2006 rates for the company's distribution business. Given the short interval between the release of the Board's decision on Hydro One's distribution rates in April 2006, and the filing of Hydro One's transmission rates application in September 2006, it is understandable that most of the compensation issues raised by intervenors in this case would be the same as those addressed in the distribution rates case.

In the Distribution decision, the Board made the following observations (in paragraphs 3.4.3 to 3.4.5):

- in future rate cases it expects Hydro One to identify what steps the company has taken or will take to reduce labour rates;
- the contrast between the compensation structures of Hydro One and some other utilities is of concern; and
- in future rate cases it expects Hydro One to demonstrate that lower compensation costs per employee have been achieved or to have concrete initiatives in place to bring compensation costs more in line with other utilities.

Hydro One stated that its approach to compensation has to be considered in light of several environmental factors. First, over 90% of Hydro One's workforce, including its engineers, is unionized, which places significant constraints on its ability to reduce compensation cost per employee. The two largest unions are the PWU and the Society. In the event of a strike by the PWU, which represents 70% of the company's workforce, Hydro One stated that it would be unable to sustain operations. Second, like many other entities in the power sector, Hydro One has an aging workforce, with over 1,000 employees eligible to retire by the end of 2008. The Company said it was working hard to strike a balance between the need to control compensation costs, and the need to hire new workers and to retain existing staff. Third, over the next few years, Hydro One must complete a large work program involving asset sustainment and major development projects.

Despite these factors, Hydro One submitted that it has had some success with its two major unions. It listed five areas in which it believes it has made gains in negotiations with the PWU (such as eliminating incentive pay) and three areas in which it has made gains in negotiations with the Society (including a pension arrangement for new Society employees that is 25% less costly than the pensions for existing employees). The Company also intends to increase its reliance on external consultants and contractors as a way to deal with its major work programs.

Hydro One filed a benchmarking study, prepared by PA Consulting in September 2006 (the "study"[13]), which compared 21 of the Company's business performance metrics with 13 North American utilities. It also provided specified wage rate and overtime policy comparisons for three job classifications with 13 Canadian regulated transmission or distribution companies. With regard to the specified wage rate and overtime policy comparisons, Hydro One's rates were highest for two of the job classifications and third highest for the other.

Hydro One argued that the benchmarking study was completed under tight time constraints on a "best efforts" basis and has several shortcomings which limit its usefulness. The study itself referred to several limitations and noted that further substantial effort and investigation would be required before any conclusions can be drawn. Hydro One stated that given more time it would not necessarily have selected the 13 companies for a benchmarking study on salaries.

PWU supported the forecast compensation costs for 2007 and 2008. It submitted that given the heavily unionized and aging workforce, and Hydro One's need to complete a major work program over the next few years, the Board should not expect any material reduction in cash compensation per employee. It also argued that the results of the benchmarking study were incomplete and inconclusive, and cautioned the Board against drawing any conclusions from the study's labour rate comparisons.

The Society argued that compensation costs for Hydro One's unionized employees are not high. It cited many of the same environmental factors noted by Hydro One as support for this view. It also submitted that total compensation cost per employee is not a useful measure of the Company's efficiency. Rather, it would be better to assess Hydro One's performance against productivity measures such as units of

[13]Hydro One was directed by the Board in the Distribution decision to prepare a high level benchmarking study for the next distribution rates case, based on a list of comparable North American companies with similar business models (transmission and/or distribution) and to report on high level comparative performance and costs information for Hydro One and the companies. The Company was directed to submit the study "on a best efforts basis" in its transmission rates application for 2007.

accomplishments per employee.

Although the Society accepts Hydro One's compensation budget, it said that if the Board continues to have concerns there are better ways for Hydro One to increase efficiency than to reduce compensation for unionized employees. It recommends that Hydro One address what the Society considers to be an unnecessarily high manager-to-employee ratio, made worse in 2006 as the result of the transfer of 155 Society-represented positions to management positions.

CCC said it continues to be concerned about the overall level of Hydro One's compensation costs. It did not, however, recommend any reduction in Hydro One's proposed revenue requirement as a result of such concerns. Instead, it urged the Board to direct the Company to work with stakeholders to propose and undertake a meaningful review of costs relative to comparators.

Energy Probe described Hydro One's overall compensation cost as clearly excessive and above market. It acknowledged that the issue requires management's attention over a number of years and said it is difficult to move towards market-based compensation every year. It argued that, as part of Hydro One's next distribution rates case, the Company should be required to provide more responsive evidence on initiatives to achieve cost per employee closer to market value.

SEC submitted that Hydro One's evidence on compensation was not responsive to the Board's direction to the Company in the last distribution rates case. It said the various negotiated gains cited by Hydro One in this application pre-dated the Board's April 2006 decision on distribution rates. It also challenged Hydro One's statement that the elimination of incentive pay for PWU-represented employees was a gain as it appears that the gain was offset by higher base pay.

Despite its concerns, SEC did not recommend any change in the forecast compensation costs except for a component of forecast management compensation. In 2006, Hydro One increased the minimum and maximum pay bands for management employees, an action SEC said was not appropriate because management salaries “set the bar for all the Company’s pay bands.” SEC recommended that the Board disallow the portion of forecast compensation costs resulting from this change without specifying an amount, or if the amount involved is material.

SEC said the Board should reaffirm the direction given in the Distribution decision and warn Hydro One that it will risk not recovering all of its compensation costs if it fails to take reasonable steps to reduce compensation.

VECC and SEC noted that the compensation comparisons provided by Hydro One look only at base salary and short-term incentives. Both intervenors recommended that in future filings Hydro One should provide information on how its total compensation, including pension and similar benefits, compares to other companies. VECC also recommended that Hydro One should develop measures that would allow parties to judge whether the size of the Company’s management group is appropriate.

Board Findings

The Board finds itself in the same position after this hearing as it was after the hearing on Hydro One’s 2006 distribution rates – it has lingering concerns about the size and growth of overall compensation costs at Hydro One. Having said that, the Board will accept the forecast compensation costs for 2007 and 2008. The evidence on compensation costs in this proceeding, while less than optimal, is sufficient to enable the Board to make this finding. While intervenors have expressed concerns about these costs, they have not been able to challenge these amounts convincingly, nor have they provided any coherent basis upon which the costs could be reduced. The Board notes that none of the intervenors recommended any disallowances except for SEC, which advocated that due to widening pay bands, any increases in management compensation should be disallowed.

Some intervenors recommended that the Board should direct Hydro One to prepare a more comprehensive study of its compensation costs and how they compare with the costs of comparable utilities. Hydro One indicated during the hearing that it is carrying out further work now that will be filed as part of its next distribution case.

The Board looks forward to the filing of a study which provides useful and reliable information concerning Hydro One's compensations costs, and how they compare to those of other regulated transmission and/or distribution utilities in North America.

To that end, the Board directs Hydro One to consult with stakeholders about the type of information to be gathered and the types of utilities and other companies that should be used for comparison purposes. The Board also expects Hydro One to gather and compare data reflecting total compensation costs, not just base salaries. Detailed comparisons of compensation costs for specific job categories are of some help in understanding how Hydro One compares to others in the industry. Equally important is the size and trend of labour costs per unit of output of various sustainment, development, and corporate activities. In the study that Hydro One is now preparing, the Board expects it to provide empirical evidence which reveals the relative productivity of its workforce in comparison to other utilities. Deficiencies in the evidence which are not fully justified could be construed against the utility in its next rates case.

The PA study filed in this Application suffered from various deficiencies and shortcomings, as noted by the authors of the study, the Applicant and the intervenors. The Board expects the new study to be comprehensive and reliable, with none of the limitations of the PA study. If Hydro One cannot correct all of these deficiencies in time for the Company's 2008 Distribution rate filing, the Board expects them to be corrected in the 2009 transmission filing.

4.3 OTHER COMPENSATION ISSUES

In its decision on Hydro One's 2006 distribution rates, the Board approved the inclusion of incentive compensation payments in the revenue requirement. The Board also made the following comment:

> While the Board does not consider the achievement of net income to be a factor that works only for the benefit of the shareholder, as customers benefit from a healthy utility through higher credit ratings and good service, the Board would be concerned if this factor predominated compared to the other factors determining incentive pay. The Board expects Hydro One to file appropriate evidence in its next main rates case to establish that none of the incentive compensation should be charged to the shareholder."[14]

Budgeted incentive payments for Hydro One's transmission and distribution businesses are $6.9 million for 2007 and $8.5 million for 2008. Hydro One did not file information that specified the portion of those amounts that relate solely to its transmission business. (As noted in section 3.2 above, Hydro One estimated that just under 50% of its full-time equivalent employees would be allocated to its transmission business.) The amount of incentive payments are linked to 14 performance measures included in the company's balanced scorecard, one of which is the achievement of net income targets.

Although the amounts may not be significant, CCC recommended that as a matter of principle none of the forecast incentive pay for 2007 and 2008 should be recovered through transmission rates. CCC submitted that this would be consistent with the methodology the Board has applied to electricity distributors. Energy Probe accepted that incentive payment targets do benefit ratepayers but argued that 25% of the amounts should be disallowed because Hydro One failed to file evidence that none of the cost should be borne by its shareholder. VECC also recommended a 25% disallowance. SEC recommended the disallowance of an unspecified portion of the forecast payments.

CCC and VECC also recommended that Hydro One be directed to establish a deferral account to track any cost reductions in 2007 and 2008 that result from Hydro One's implementation of the findings of the Agency Review Panel, established in January 2007. It released its Phase I report on executive compensation at Hydro One and four other provincial electricity sector institutions on June 27, 2007. At that time, the Minister

[14] Decision With Reasons, RP-2005-0020/EB-2005-0378, April 12, 2006. para. 3.4.6.

of Energy announced that he has directed each institution to implement the Panel's recommendations.

Board Findings

The Board accepts the inclusion in the revenue requirement of the forecast incentive payments.

The concern of intervenors is the inclusion of a net income target in Hydro One's balanced scorecard, which is the basis for incentive payments. The Board acknowledges that its 2006 Distribution Rate Handbook ("2006 EDR Handbook") stated that incentive payments related to benefits to shareholders would not be recoverable in the 2006 revenue requirement of a distributor. In the Board's view, our decision to allow incentive compensation costs in Hydro One's transmission revenue requirement is not in conflict with the 2006 EDR Handbook. First, net income is only one of 14 performance measures in Hydro One's balanced scorecard; there is no evidence that the net income performance measure predominates, which was the concern expressed by the Board in the Hydro One distribution decision. Indeed, Hydro One pointed out that incentive payments are contingent on meeting a range of performance measures; no payouts would occur if the net income target were met but other measures were not achieved. Second, there is no evidence that would allow the Board to make an objective determination of how much of the forecast incentive payments relate to shareholder benefits. Even if that were possible, it appears to the Board that the amount, if any, would be very small given that the total incentive payments allocated to the transmission business for the test years are not particularly significant.

Executive compensation costs in Hydro One's application obviously could not have reflected the recommendations of Agency Review Panel. The impact of the recommendations on Hydro One's executive compensation for 2007 and 2008 is unknown given that the Company's Board of Directors would only recently have started the implementation process. In addition, the effective date of any new compensation practices at Hydro One is also unknown. Accordingly, there is no way to predict if the impact in 2007 and 2008 of the implementation of the Agency Review recommendations will be significant.

The Board would generally not require a utility to track variances in routine costs when new information about the extent of those costs in the test years becomes known only after the rates hearing is completed and the parties have submitted argument.

In this case, the Board believes an exception is warranted. In his announcement of the release of the Panel’s report, the Minister of Energy noted that the government wants to ensure that compensation for top executives strikes an appropriate balance between being competitive on the one hand, and fair to ratepayers, on the other. The Board directs Hydro One to track any reduction in executive pay during 2007 and 2008 that results from implementing the Panel’s recommendations and to report that amount at its next transmission rate case.

5. CAPITAL EXPENDITURES

Hydro One's updated evidence shows a significant increase in transmission capital spending. The Company has requested approval for capital expenditures of $691.5 million in the 2007 test year and $768.2 million in 2008, as shown in Table 4. The 2007 amount is 72% higher than bridge year levels and the 2008 amount is 11% higher than 2007. The bridge year amount of $401.6 million was 15% higher than 2005 levels. The two main areas of this growth are the Sustaining and Development capital budgets, which comprise over 90% of the total proposed capital expenditures.

Table 4: Capital Expenditures 2003 – 2008

	Historic			*Bridge*	*Test*	
$ millions	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Capital Expenditure by Category						
Sustaining	$160.3	$173.7	$168.9	$178.5	$288.1	$295.6
Development	59.5	217.3	134.6	179.4	298.7	409.4
Operations	38.9	20.7	10.2	9.4	20.1	20.4
Shared Services & Othe	28.7	20.2	35.5	34.1	84.6	42.7
Total*	$287.4	$431.9	$349.2	$401.4	$691.5	$768.1
Year over year % change						
Sustaining		8.4%	-2.8%	5.7%	61.4%	2.6%
Development		265.2%	-38.1%	33.3%	66.5%	37.1%
Total Capital Expenditures		50.3%	-19.1%	14.9%	72.3%	11.1%

**Note: Totals may not add due to rounding.*
Source: Exhibit D1/Tab3/Sch1

Hydro One defended its capital budgets on the basis of what it considers a comprehensive planning process that encompasses the effects of an aging asset base, the results of the asset condition assessment and monitoring of failure rates. In addition, its process takes into account significant expansion of the transmission system to accommodate what the Utility describes as the changing electricity infrastructure needs of the province.

Intervenors generally limited their arguments to the Sustaining and Development budgets.

5.1 SUSTAINING

The Sustaining budget is growing from $178.5 million in 2006 to $288.1 million in 2007, an increase of 61% with a further small increase in 2008 of 2.6%.

Sustaining expenditures include the cost of investment required to replace or refurbish components to ensure that existing transmission system facilities function as originally designed. The evidence showed that these capital expenditures are largely driven by the same factors as OM&A spending, that is, asset condition assessment, asset aging records and data respecting failures and outages.

Intervenors' concerns fell largely into three categories: concerns that the asset assessment was not sufficiently robust to accurately determine the need to replace the assets; criticism that Hydro One spent insufficient funds on asset maintenance in previous years; and concerns that Hydro One would not be able to spend all the funds budgeted.

Part of Hydro One's asset analysis relied on information on asset failure rates. VECC argued that updated information on failure rates showed that outages were actually lower than those used to develop the sustaining budget. In addition, VECC argued that the 2006 asset condition assessment was not much different than the previous (2003) assessment. Overall, VECC questioned whether this information justified the large increase in sustaining capital expenditure.

SEC reiterated the arguments it made with respect to the OM&A budget, namely that Hydro One had ample information regarding the state of its asset base during the historic period to justify gradual increases in expenditures so as to avoid major increases in the test years. SEC suggested that this demonstrated that the Sustaining capital budget should be reduced, but did not suggest a specific reduction in the test years.

AMPCO's position was that the evidence on asset aging was not clear, and urged the Board to direct Hydro One to provide better evidence of asset aging at its next rate hearing. AMPCO also questioned the evidence that system performance was deteriorating. In addition, AMPCO cited Hydro One's performance compared to analogous utilities. Further, AMPCO argued that there should be significant sustainment benefits arising from the proposed large increase in development spending, which will result in the replacement or upgrading of existing components in capital projects. AMPCO submitted that the sustainment budget should be reduced to $215 million in 2007 and $255 million in 2008.

Hydro One responded that its capital spending plans are based on multi-year trends in asset failures, and a slight reduction in failures in 2006 would not cause it to alter its plans for single year results or for a single asset group.

Hydro One also argued that the asset condition assessment methodology for 2006 was markedly different than the 2003 study, with a larger asset base, refined techniques, improved data quality and enhanced algorithms. Hence, the results of the two assessments were not directly comparable. Hydro One maintained that the evidence it had in the earlier period, when it completed its business planning, did not justify higher expenditures in the years leading up to the test year. There was no reason to increase expenditures during that period, given that the information available at that time did not show a need to accelerate replacements or upgrades. In addition, Hydro One asserted its evidence points to increasing numbers of mid-life and end-of-life assets, largely the result of a high growth period in the 1950s and 1960s.

PWU supported the Hydro One request for Sustaining capital, citing the asset aging and performance evidence as well as raising the risk to reliability, service quality, safety and increased maintenance costs, if capital spending were to be reduced from planned levels. The PWU stated that some of the increased budget for Sustaining capital was a result of the increasing cost of material and equipment in a time of unprecedented transmission development globally.

Board Findings

The findings in this decision on OM&A expenditures are very relevant to these findings, as increases in both cases are largely based on aging assets. Hydro One is seeking approval of a sustainment capital budget that increases by an extraordinary 61% from 2006 to 2007. Intervenors are understandably concerned. Their concerns regarding asset assessment information are equally relevant to sustainment capital and OM&A.

The Board accepts that Hydro One’s asset assessment methodology and information is improved over previous years. However, it still lacks clarity and robustness. While Hydro One’s quantitative evidence is not compelling, the Board finds that Hydro One’s qualitative evidence provides assurance that capital costs are escalating significantly. The Board accepts that the high growth period of the 1950s and 1960s likely results in a similar period of a high number of assets coming to the end of their useful life. Though the most recent failure information did show some improvement in failure trends, the Board also acknowledges Hydro One’s position that plans for sustaining investment must take into account more than a one-year or short-term improvement when planning capital spending programs. In addition, the Board notes Mr. McQueen’s evidence that increasing costs are also a result of escalating global demand for material and equipment. No intervenor refuted this evidence. Therefore, the Board accepts that both the number of replacements and the cost per replacement are escalating.

Intervenors asserted that Hydro One could have avoided the proposed significant increase in expenditures by recognizing the asset aging problem sooner and smoothing the expenditures over the past several years. The Board accepts that it is difficult to smooth a capital budget over several years and that it is both imprudent to invest too soon in capital replacements and imprudent to wait until the system deteriorates to very low levels of reliability before action is taken. Hydro One must balance the immediate investment needs of the system with an eye to proactive action to prevent an unsupportable level of failure and reliability levels.

AMPCO submitted that a large capital investment program should result in lower sustaining capital expenses and suggested that the Board should take this into consideration. The Board agrees that the replacement of old equipment during a capital program should have the effect of lowering sustaining capital costs. We anticipate that there will be a lag in the effect, and expect Hydro One to provide evidence on the 2009 and 2010 sustainment capital benefits of 2007 and 2008 capital expenditures as the newer facilities come into service and replace the aging fleet. However, the Board does not accept AMPCO's rationale for its recommended reduction to OM&A expenses for the test years.

The Board approves the amounts applied for sustaining capital in 2007 and 2008 rates. As noted earlier in this decision in the OM&A chapter, the Board must have improved asset aging data for the next Hydro One cost-of-service proceeding. In approving the Sustaining capital investment plans, the Board expects Hydro One to continue to improve its asset condition assessment work and its work on the influence of asset aging on investment levels. The Board refers the reader to Chapter 3 of this decision for the Board's direction on developing this information.

5.2 DEVELOPMENT

The Development budget is growing from $179.4 million in 2006 to 298.7 million in 2007, an increase of 66% with a further increase of 37% in 2008 to a level of $409.4 million.

The Development Capital category covers funding for projects related to new or upgraded transmission facilities. Those facilities provide inter-area network transfer capability provide adequate capacity to deliver electricity to local areas, connect new generation and load customers to the transmission system, and maintain the performance of Hydro One's transmission system in accordance with Delivery Point Performance Standards. Hydro One showed project detail for all projects with budgets in excess of $3 million.

Hydro One classified the proposed Development projects on the basis of in-service date and the nature of the approval the applicant was seeking from the Board.

Category 1 included 15 projects with in-service dates in 2007 and 2008. The Applicant seeks to include the budgeted expenditures in the rate base the Board for 2007 and 2008.

Category 2 included six projects with in-service dates in 2009 and 2010. These projects do not require Board approval pursuant to section 92 (leave to construct), but will come before the Board again when the Company applies to include the costs associated with them in rate base. As these projects require significant spending in 2007 and 2008, the Applicant seeks assurance from the Board that the projects appear to be necessary, and the costs of the projects appear to be reasonable and prudent. The most significant project in this group is the Claireville/Cherrywood 500 kV circuit unbundling project.

Category 3 included seven projects that will require section 92 approvals. In the course of those proceedings the Company will present evidence establishing need and cost. However, for reasons that will be outlined below, Hydro One requested a determination by the Board of the need for the Leaside to Birch Junction project in this proceeding.

Category 4 consisted of two projects which may be part of the Integrated Power System Plan process, and which will have in-service dates beyond the test years. The evidence regarding these projects will be brought before the Board in a subsequent rate proceeding for inclusion in rate base. The Company did not seek any decisions from the Board with respect to these projects in this proceeding, and the Decision does not comment on those projects.

Board Findings – Development Category 1 Projects

In the Board's view, Hydro One's justification for the bulk of Category 1 projects was extensive and thorough. Support for these projects from sources such as the OPA, the IESO and preliminary documents related to the IPSP is persuasive. The Board also notes the support provided by Toronto Hydro and OPG for some of these investment projects.

There were no Intervenor or Board staff concerns with any of the Category 1 projects. The Board is of the view that these projects are well documented and substantiated by the evidence presented by Hydro One. The Board approves the inclusion into rate base of the budgeted amount of these projects. The total amount projected to be included in rate base in connection with the Category 1 projects is $256 million.

Board Findings – Development Category 2 Projects

Of the Category 2 projects, the Claireville/Cherrywood project was the most discussed. This project, which has an expected capital cost of $107 million, involves unbundling two 500 kV lines that are now connected and operated as a "super" circuit. Currently when one of the two circuits is out of service due to a planned or forced outage, generation connected to the 500 kV system in eastern Ontario must be curtailed. If constructed, the project will result in over 3,000 MW of transfer capability between the Claireville and Cherrywood transmission stations. The project was included in the June 2006 and March 2007 editions of the IESO's Ontario Reliability Outlook ("ORO").[15]

[15] In its final argument, the IESO said that "The inclusion of a project in the ORO … underscores the IESO's assessment that a proposed project meets a reliability need that has been identified or confirmed by the IESO. … To be clear, the inclusion in the ORO is not a directive for a transmitter or other entity to undertake construction, but agreement from the IESO that the proposal meets a specific need to improve reliability of the IESO-controlled grid or the load it serves."

Intervenors were generally in support of the Claireville/Cherrywood project and found the economics and rationale compelling. Toronto Hydro supports the project as it will improve supply reliability to Toronto's distribution system. OPG supports the Claireville/Cherrywood project as it is critical to the integrity of the power system, and benefits the electricity system and the operations and safety of the Darlington Nuclear station once completed. According to OPG, the project will reduce the risk of sudden generation reduction, which results in a revenue loss per event in the range of $0.5 million to $1 million.

Toronto Hydro also supported the Hydro One Development Capital program, making submissions for 16 specific projects cited in the Hydro One evidence, including several Category 2 projects. PWU supported the Hydro One Development capital budget proposals, citing the IPSP, OPA procurement activities and the IESO ORO reports as justification for these investment plans.

Regarding the Category 2 projects, including Claireville/Cherrywood, VECC was concerned with Hydro One's desire for assurance from the Board that "the capital program that the company is proposing is an appropriate approach, subject to coming back later to demonstrate to you that the costs have been reasonable and prudently incurred." [16] VECC submitted that the Board should not grant this assurance and that any such conclusion should be no more than an observation that the projects are reasonable.

The Board agrees with VECC. The costs of these projects will be subject to approval in a future proceeding. However, the Board does make the observation that these projects appear to be needed and, based on the limited evidence available, the Board did not identify any concerns about the proposed costs. The need for at least some portion of the Claireville/Cherrywood project appears to be non-discretionary. As Hydro One will be returning in 2008 for a 2009 test year application, the Board expects to see updates and progress reports on all these projects at that time, for final scrutiny and

[16] Tr. Vol.2, p.121

consideration of approval of the inclusion of these amounts into rate base. For discretionary projects, the Board expects Hydro One to quantify the reliability and other benefits of the projects.

Board Findings – Development Category 3 Projects

In this proceeding, the Board need make only one finding regarding the Category 3 projects. This is the need determination for the Leaside TS to Birch Junction TS project. Approval of all of the elements of the other projects will be covered under Leave to Construct (section 92) applications.

The Settlement Proposal stated:

> The parties agreed that the Applicant has demonstrated the need to relieve loading on the existing 115kV connection lines and Leaside and Birch Junction TSs.
>
> The Applicant has agreed that the issues regarding options, alternatives and costing of the mitigating alternatives will be deferred from this rate application to be dealt with in a separate section 92 application to the Board.

Notwithstanding this settlement, the Board determined that the need for this project should be examined on the record. Hydro One presented witnesses to address this issue in the oral hearing and provided evidence of need supported by the IESO and Toronto Hydro. Other intervenors did not comment on the evidence respecting need but submitted that the scope of the finding that the Board makes should not be broader than that agreed to in the Settlement Proposal.

The Board agrees. The evidence clearly demonstrates the need for the project as it addresses specific reliability issues. The Board finds that the need to relieve loading on the existing lines between Leaside TS and Birch Junction TS has been demonstrated. The Board accepts that the issues on options, alternatives and costing of mitigating alternatives be deferred to a section 92 application, as agreed to by parties in the Settlement Decision.

5.3 ECONOMIC JUSTIFICATION OF THE NIAGARA REINFORCEMENT PROJECT

The Board in its July 8, 2005 Decision on the Niagara Reinforcement Project ("NRP") (RP-2004-0476), granted leave to construct without a determination that Hydro One had proven the economic benefits of the project. As part of that decision, Hydro One was directed to demonstrate the benefits when seeking to recover the costs associated with the project. The Company provided evidence respecting the economic benefits of the project in this proceeding.

Hydro One indicated that the NRP, when operational, will increase import capability from New York by 350 MW. To assess the economic benefit of the project, Hydro One compared, for a 30-year period, the cost of acquiring additional generation capacity through the installation of a 350 MW single cycle combustion turbine unit with the NRP costs. According to Hydro One's evidence the present value of the cost of the 350 MW combustion turbine unit is $309 million and the present value of the cost of the NRP of $103 million. The implied net present value is about $200 million.

Part of the evaluation involved estimating the difference in cost between buying energy in the New York market versus producing energy in Ontario from the combustion turbine. The difference was estimated to be about $70 million in favour of the New York purchase option. The assumptions underlying this estimation were the subject of significant cross examination concerning energy price differentials between the New York and Ontario markets.

Intervenors generally did not comment on the NRP economic justification issue in their final submissions. Only VECC raised concerns regarding Hydro One's analysis. While VECC accepted that the NRP offers benefits that allow new generation in the Niagara Peninsula and increases access to imports, it questioned the 30-year time horizon of the analysis. VECC suggested that the Board direct Hydro One to revise its economic analysis of the project, add congestion costs to the calculation and file the revised analysis prior to requesting any determination from the Board that all of the costs of the NRP (when in-service) be recovered from ratepayers.

Board Findings

While the Board agrees that the further analysis suggested by VECC might have been helpful, the Board finds it was reasonable to compare the transmission reinforcement to a 350 MW single cycle gas combustion turbine. The Board accepts that the need for NRP should be assessed based on the circumstances that existed at the time the project was initially conceived and the information available at that time. For this project, the relevant time period was 2004/2005. When the historical context is taken into account, the economic evaluation provided by the Company is sufficiently persuasive to allow the Board to make this finding. The Board accepts the expenditures associated with the project as prudent, and requires no further analysis from Hydro One to justify the expenditures incurred to date.

However, the Board is concerned that the economic evaluation presented by the Company had shortcomings, which should not be repeated in future applications. In preparing economic justification for similar projects, the Board expects a more complete, precise and rigorous evaluation which includes an analysis of the option of not proceeding with a project, (the “do nothing” scenario) and sharply improved efforts to quantify reliability benefits.

Hydro One is seeking extraordinary relief to recover the costs of this uncompleted project in rate base. The discussion of this aspect of the NRP and the Board’s decision on the matter can be found in Chapter 6 of this Decision.

5.4 OPERATIONS AND SHARED SERVICES

Shared Services capital spending for the test years is substantially higher than spending in 2006 and earlier years. This is mainly due to the Hydro One's Cornerstone information technology project.

Phase One of the Cornerstone project involves the replacement of the PassPort asset and work information system with an integrated Enterprise Asset Management application. The evidence showed that capital spending on this phase alone will be $102 million in 2007, with $57 million allocated to the transmission business.

Although there was significant cross examination on this project, intervenors did not address this issue in their final arguments. According to the Company's evidence, the net present value of the first phase of the project is a $60 million cost over the seven years from 2008 to 2015. Hydro One asserts that the benefits of the project will follow full implementation.

Board Findings

Hydro One was able to demonstrate that the Company's information systems cannot provide the information required to efficiently manage its work and assets. Indeed, the difficulty in getting robust asset aging information in this proceeding was partially attributed to the poor information systems. The Board accepts the Operations and Shared Services capital costs for the 2007 and 2008 rate years, including funding for the Cornerstone project. The Board anticipates greater scrutiny of the cost of Cornerstone in the next transmission rate proceeding when more detailed information will be available.

5.5 CAPITAL CONTRIBUTIONS

Hydro One estimated the total cost of Cambridge Preston TS project cost to be $21.2 million. The Company is not requiring a capital contribution from the customer based on the Company's interpretation of the Transmission System Code (TSC). The appropriate interpretation of the TSC regarding capital contributions is being considered in another Board proceeding, the Connections Procedures case (EB-2006-0189). The decision in that case will clarify the interpretation of the relevant sections of the TSC regarding capital contributions.

VECC submitted that if the EB-2006-0189 decision is not rendered in time to have it reflected in the revenue requirement for 2007 and 2008, then a deferral account should be set up to track the impact of any capital contributions, should that decision reflect an interpretation of the TSC contrary to that taken by the Company in this proceeding. Hydro One argued that a deferral account would not be necessary, but if it is determined that a capital contribution is required, a deferral account could be used to adjust rate base. Hydro One indicated that were a capital contribution required, the customer would have to pay $17 million. The Board estimates the effect on the revenue requirement of such a capital contribution would be less than $2 million in 2007 and 2008.

Board Findings

Since the outcome of the EB-2006-0189 proceeding is not known, the Board accepts VECC's position that a deferral account should be established. Entries in the account will be necessary only if the Board's decision in EB-2006-0189 results in the customer being required to make a capital contribution in respect of the Cambridge Preston TS project.

5.6 EARNINGS/SHARING MECHANISM

While VECC and CCC did not recommend a reduction in the proposed capital budget, they did suggest that Hydro One's capital spending plans were too ambitious and there was a risk that they may not be completed as planned. VECC also questioned Hydro One's prioritization methods. VECC suggested that underspending of the capital budget be returned to ratepayers through an earnings sharing mechanism. CCC supported this recommendation.

Hydro One submitted an earnings sharing mechanism was not necessary and cited evidence that the capital additions expected to come into service during the test years were manageable. The Company also pointed out that earnings sharing proposal would be inconsistent with a cost-of-service filing that is based on future test years.

Board Findings

Hydro One submitted evidence comparing the Company's actual capital spending to budget forecasts for the years 2003 through 2006. The results show variances of up to 20%, both positive and negative. The Board is concerned with the magnitude of the variances but has no basis to believe that the forecast budget for 2007 and 2008 will be under spent. The Board finds that an earnings sharing proposal to guard against variances to budget is unnecessary. As a result of the Board's decision to deny Hydro One's request for a 2009/2010 RRAM, the Board expects Hydro One to file a cost-of-service application for 2009 rates. At that time, the Board expects Hydro One to provide evidence on 2007 and 2008 actual capital spending compared to the Board-approved budget. Future decisions on capital budgets will be informed by Hydro One's performance to plan.

SUMMARY BOARD FINDINGS ON CAPITAL EXPENDITURES

In summary, the Board approves the capital budget for 2007 and 2008 as presented by Hydro One. This includes the budgets for all categories of the capital spending including the Operations and Shared Services categories. The Board reiterates the need for more robust data regarding some of the categories of capital expenditures, as outlined more fully in text above, which the Board expects Hydro One to file in its next transmission rates application.

6. HYDRO ONE'S REQUEST FOR SPECIAL TREATMENT FOR DESIGNATED TRANSMISSION PROJECTS

Hydro One requested special regulatory treatment for four transmission projects: the Bruce Project, a proposed new transmission line to support additional electricity generation from Bruce Power and proposed or possible wind generation projects; the Quebec Intertie, a 1,250 MVA interconnection with Hydro-Québec's transmission system; the installation of static VAR compensators in southwestern Ontario; and the Niagara Reinforcement Project ("NRP"), a new transmission line that is virtually complete. Table 5 shows actual and forecast spending on these projects.[17]

For each of these projects, Hydro One proposed:

- Increasing rate base as expenditures are incurred rather than waiting until the projects are in-service;[18]
- Commencing amortization of the project costs as funds are spent (that is, before they are in-service and are being used) and including the amortization in the revenue requirement; and
- Holding Hydro One financially harmless in respect of the designated projects in the event of abandonment for reasons outside the Company's control.

[17] In its evidence, Hydro One referred to these four projects as "supply mix capital projects". It was not clear to the Board why Hydro One decided to use that description. The Minister of Energy's June 13, 2006 directive to the OPA on the supply mix goals of the Integrated Power System Plan did not mention any particular transmission projects. Two of the projects – the Quebec Intertie and the NRP – were planned and approved before the Minister issued the directive. The other two projects are being initiated before the OPA files its IPSP. In this chapter of the Decision, the Board refers to these projects as the "designated projects", not "supply mix capital projects."

[18] Hydro One also requested that this adjusted rate base would be used to set the revenue requirement under the Company's proposed revenue requirement adjustment mechanism for 2009 and 2010. As noted in Chapter 2 of this Decision, the Board denied Hydro One's request for the RRAM. Therefore, this request is now moot.

The proposed approach differs from the conventional regulatory approach of capitalizing interest costs during construction, and waiting until the project is in-service to transfer the costs to rate base and to commence amortization.

Table 5: Actual and Forecast Expenditures on the Designated Projects

($ millions)	*Historic*		*Bridge*	*Test*		*Total (including future years)*	*Expenditure Period*
	2004	*2005*	*2006*	*2007*	*2008*		
Bruce Project	-	-	-	5	52	613	2007 - 2011
Quebec Intertie	-	-	1	65	48	115	2006 - 2009
Static Var Compensators	-	-	-	-	10	54	2008 - 2009
Niagara Reinforcement	1	35	61	2	0	101	2004 - ?? *
Total	**1**	**35**	**62**	**72**	**110**	**883**	

* Project is almost complete but work has been suspended.

Only three projects were designated for special treatment in Hydro One’s September 2006 application; the NRP was added when the Company amended its application in February 2007. As most intervenors noted, the NRP is fundamentally different from the other three projects in that it is substantially complete but work has been halted because of events outside of Hydro One’s control. In this chapter, the Board deals with the other three projects in section 6.1 and then separately considers the NRP in section 6.2.

6.1 BRUCE PROJECT/QUEBEC INTERTIE/STATIC VAR COMPENSATORS

Hydro One’s primary rationale for the proposed special treatment is that the designated projects require significant expenditures, must be initiated in the short term, have long lead times, are driven by Ontario’s supply mix initiatives, and are exposed to risks over which Hydro One has limited or no control or influence.

Hydro One submitted that its proposed regulatory treatment is consistent with the approach recently adopted by the Federal Energy Regulatory Commission ("FERC") in the United States, will result in a neutral bottom line and will mitigate rate shock and, will result in ratepayers, the primary beneficiaries of the projects, bearing the risks.

FERC Policy and Precedents

To stimulate private capital investment in transmission infrastructure, the United States Congress directed FERC to establish incentive-based rate treatments to promote investment in transmission infrastructure. In 2006, FERC issued Order No. 679, which identifies the types of rate incentives that FERC will consider for federally-regulated transmission entities when justified by the specific facts and circumstances.[19] The identified incentives include higher rates of return on equity for specific transmission investments; the inclusion of 100 percent of construction work in progress ("CWIP") in rate base; and the assurance of recovery of the costs of a project that is abandoned for reasons outside the control of the utility.

In its evidence, Hydro One cited four transmission projects for which FERC approved various incentives. Table 6 summarizes those projects and the incentives granted by FERC. The American Transmission Company decision pre-dated Order No. 679. The other decisions were issued at the same time or after the issuance of Order No. 679[20].

[19] Federal Energy Regulatory Commission, Order No. 679, *Promoting Transmission Investment Through Pricing Reform*, July 20, 2006. In December 2006, after rehearing certain issues, FERC issued Order No. 679-A, which clarified and amended some aspects of the original order but did not change the overall framework for transmission incentives.

[20] After the oral hearing was completed, Staff circulated *Commonwealth Edison Company*, 119 FERC ¶ 61,238 (2007), the most recent decision on incentives for transmission projects, to all parties. The Board did not rely upon it in making its decision.

Table 6: Recent FERC Cases on Incentives for Transmission Projects

Proponent	Project	Cost (US $ millions)	FERC Incentives
American Transmission Company[21]	Various proposed projects over 10 years	Up to $2,800	▪ 100% of CWIP in rate base ▪ Expense pre-certification costs ▪ Increased ROE
American Electric Power[22]	550 miles of 765 kV lines from West Virginia to New Jersey Target completion date – 2014	$3,000	▪ 100% of CWIP in rate base ▪ Option to expense pre-commercial costs ▪ Increased ROE
Allegheny Energy[23]	240 miles of 500 kV lines from Pennsylvania to northern Virginia Target completion date – 2011	$820	▪ 100% of CWIP in rate base ▪ Expense pre-commercial costs ▪ Increased ROE ▪ 100% of prudently-incurred costs on abandonment
Duquesne Light[24]	New high voltage line; increase capacity of underground 345 kV lines with advanced technology; upgrade certain 69 kV facilities to 138 kV. Target completion date – 2009 (some work already complete)	$184	▪ 100% of CWIP in rate base ▪ Expense pre-commercial cost ▪ Increased ROE ▪ 100% of prudently-incurred costs on abandonment

While the FERC incentives listed in Table 6 are intended to encourage investment in transmission projects, Hydro One stated a different rationale. In response to a question from the Board Panel, Hydro One said:

> What we're asking for is not an incentive in the traditional use of that word, as far as to provide some incentive to encourage a certain behaviour … [what] we're asking for is special regulatory treatment for these projects as opposed to an incentive to do something before the fact.[25]

[21] *American Transmission Company LLC*, 105 FERC ¶ 61,388 (2003), and *order approving settlement*, 107 FERC ¶ 61,117 (2004).

[22] *American Electric Power Service Corporation*, 116 FERC ¶ 61,059 (2006), and *order on rehearing*, 118 FERC ¶ 61,041 (2007).

[23] *Allegheny Energy, Inc*., 116 FERC ¶ 61,058 (2006), and *order on rehearing*, 118 FERC ¶ 61,042 (2007).

[24] *Duquesne Light Company*, 118 FERC ¶ 61,087 (2007), rehearing pending.

[25] Tr., Vol. 7, p. 62

In a concurring statement appended to FERC's decision on the rehearing of the Allegheny Energy application, Commissioner Suedeen Kelly provided a framework for evaluating incentive proposals. She stated:

> I deem it important to identify and assess the following six characteristics of any transmission project in order to make reasoned and consistent decisions on requests for incentives for the project: (1) the public interest benefits of the project; (2) the cost of the project in absolute terms; (3) the cost of the project in proportion to the current transmission rate base of the applicant; (4) the difficulty of completing it due to the number of jurisdictions traversed and whether they are jurisdictions the applicant regularly deals with; (5) the difficulty of relying on normal rate recovery methods due to the length of time it will take to complete; and (6) whether the applicant would otherwise be required to build the project even without an incentive.
>
> The comments submitted in connection with Order Nos. 679 and 679-A, and the experience gained in working on individual incentive cases over the past year lead me to conclude that these particular characteristics are most relevant to deciding whether to award incentives.[26]

A witness for Hydro One said Commissioner Kelly's six criteria "are important characteristics and I believe they're consistent with the criteria that Hydro One has put forward, in terms of assessing the supply mix projects."[27]

Mindful of the fact that there is no government directive in place comparable to that which resulted in FERC Order No. 679, the Board found Commissioner Kelly's framework and criteria of assistance when it considered whether the special regulatory treatment sought by the Applicant for the designated projects was necessary or warranted. While certain of the criteria have reduced significance (for example, the traversing of jurisdictional boundaries poses different problems in the United States than in Ontario[28]) others, such as the costs of designated projects in proportion to rate base

[26] *Allegheny Energy, Inc*., 118 FERC ¶ 61,042 (2007), Kelly concurring statement, p. 1.

[27] Tr., Vol. 6, p. 147

[28]PWU noted, the lion's share of the cost of the Quebec Intertie project will be borne by Hydro-Québec, a fact which may increase the risks associated with that project because it might be dependent on decisions made in Quebec and so beyond the control of Hydro One. Other intervenors, such as CCC, submitted that Hydro One faced no appreciable or substantial jurisdictional risks.

and whether normal rate recovery methods can be relied upon, are of equal significance and importance here.

Many of the intervenors made reference to the criteria in their closing submissions. While none of the intervenors challenged the public interest benefits or the absolute cost of the designated projects, several of the intervenors observed that the aggregate costs of the projects relative to the Applicant's rate base did not present significant risk. Energy Probe noted that, in aggregate, the cost of the projects (including NRP) is less than one-seventh of Hydro One's current rate base, and would be only about 12.8% of Hydro One's forecasted 2008 rate base. PWU made a similar observation. In Energy Probe's view, costs of that magnitude should not create any special risks for the utility, assuming vigilant management. Energy Probe argued that the aggregate costs of the designated projects are comparable to rate base additions in recent years, when no rate changes occurred.

The other criterion which elicited significant comment from the intervenors was whether conventional rate recovery methods were adequate, given the costs of the designated projects and the time period over which the costs would be advanced. It was Hydro One's position that the designated projects are extraordinary in many respects when compared to those normally undertaken by a transmission company, and so merit special rather than conventional regulatory treatment.

VECC submitted the evidence established that the investment community does not perceive an impending risk that would necessitate special treatment. VECC added that regulators in Ontario have considerable experience in dealing with such matters and have traditionally allowed recovery of costs under conventional methods provided the utility has acted responsibly.

CCC submitted that there is no reason to deviate from conventional regulatory approaches and to compensate Hydro One now for risks that have not, and may not, materialize. CCC characterized the proposal by Hydro One to recover a return on expenditures as they are incurred (and to allow for amortization to also be recovered) as a significant departure from the accepted regulatory treatment for capital projects. CCC also pointed out that the bond rating agencies have either maintained positive ratings or improved ratings for Hydro One, without any reference to a need for extraordinary treatment for these projects.

Energy Probe addressed each project separately, and concluded that conventional regulatory treatment was appropriate for all three of the designated projects.

AMPCO submitted that there is no evidence to suggest that, in the absence of special treatment, Hydro One will be left with abandoned or stranded assets from undertaking these projects. AMPCO pointed out that Hydro One may always seek relief from the Board should such an event occur.

Both CCC and VECC were of the view that Hydro One's proposal was solely directed to risk management. VECC observed that the underlying rationale of the FERC initiatives was to provide an incentive to private U.S. transmission owners to make investments, a rationale not present in this case.

The PWU similarly noted that the request for special treatment of the designated projects is not an incentive in the traditional use of the term, as Hydro One is committed to undertake the projects in any case. However, the PWU also submitted that the request is one of fairness in that Hydro One should be protected from any financial harm for reasons outside its control.

Impact on Ratepayers

Hydro One's application states that approval of special regulatory treatment for the designated projects would lower and smooth customer rate impacts, and have a positive impact on the Company's credit ratings and borrowing costs, to the benefit of current customers.

Hydro One also suggested its proposal would result in a neutral financial effect. That conclusion is based on qualitative information obtained in a seminar presented by the National Association of Regulatory Utility Commissioners; Hydro One confirmed that no quantitative analysis had been completed to confirm that the proposed approach would result in a neutral financial effect. In response to an interrogatory, Hydro One advised that it had not estimated the impact of the proposal on its credit rating or borrowing costs; however, in response to another interrogatory, Hydro One stated that the Company may be slightly better off financially under the proposal.

VECC estimated a substantial favourable effect on Hydro One's income by 2010, based on the differential between a pre-tax return on equity and AFUDC. VECC submitted that while Hydro One's intent may not have been to be financially advantaged, the result is that it will derive a substantial financial advantage from the proposed treatment. SEC provided estimated impacts over the long term in noting the proposal is, in essence, an interest free loan to Hydro One from ratepayers that will be paid back over 45 years.

Hydro One also argued that a primary benefit of the proposed special treatment is to avoid rate shock for consumers. VECC, in its argument, notes that Hydro One has done no specific analysis of the rate impact of its proposal. VECC provided its own analysis of total bill impact based on conventional rate making practice. VECC submits that the result (less than 0.3% increase in 2012) does not constitute rate shock.

Energy Probe said that the designated projects are each small, relative to Hydro One's overall rate base, and as the projects have unique in-service dates scattered fairly evenly over future years, the overall rate impact under a conventional ratemaking approach is already smooth.

Board Findings

AMPCO, CCC, Energy Probe, SEC, and VECC argued that the proposed special regulatory treatment for the designated projects should be rejected by the Board. PWU was the only intervenor to support Hydro One's proposal. In summary, the arguments against the proposal were:

- There is no reason why Hydro One should be compensated now for risks that may not materialize.

- The proposal is a significant departure from conventional regulatory treatment for capital projects. The Board should permit departures only under very exceptional circumstances and Hydro One has failed to establish that such exceptional circumstances exist. To allow Hydro One the relief it is seeking would set a precedent that may prompt other Ontario utilities to seek similar relief. Before setting such a precedent, the Board must be satisfied that conventional regulatory treatment is inadequate to meet needs such as those associated with the designated projects.

- If construction is delayed or if there are abandonment issues, Hydro One would be free to come to the Board for relief.

- Hydro One has not established that it is now subject to an increased risk with respect to the recovery of the costs associated with these projects.

- Hydro One has not established the need for "incentives" to undertake or complete those projects.

- FERC precedents arise out of a different regulatory regime and are not applicable in the Ontario context.

- The benefits to ratepayers as articulated by Hydro One have been overstated.

The Board shares these concerns and finds that a departure from conventional regulatory treatment has not been justified.

There is no evidence in this case that any regulator other than FERC has approved a package of special regulatory treatments like those advocated by Hydro One. FERC regulatory initiatives can be important guidance in some cases and the Board will continue to monitor FERC's actions to incent new transmission. However, the Board is not convinced that FERC's approach to incentives for transmission investments justifies the special treatment that Hydro One has requested. The cost of the designated projects, while large in absolute terms, is not particularly significant in relation to Hydro One's rate base, and there is no evidence that Hydro One will have difficulty financing the projects under conventional regulatory treatment.

The Board is not persuaded that ratepayers would benefit from the proposed special regulatory treatment. Specifically, the Board does not accept Hydro One's argument that the treatment would result in revenue neutrality and rate smoothing. The evidence from Hydro One on this point was in conflict and lacked substance.

The Board acknowledges Hydro One's concerns about the magnitude of its capital expansion program. At the same time, based on the evidence from the credit rating agencies, the Board is not convinced that Hydro One will be unable to finance the capital program under the conventional approach.

The Board is of the view that conventional regulatory treatment for the three designated projects provides the appropriate balance between the interests of ratepayers and utilities. The Board agrees with the consensus position of the intervenors that the mitigation of losses that have not, and might not, occur is unnecessary and not appropriate. There is nothing in the record that would justify the burdening of ratepayers with such losses. In addition, Hydro One is reminded that it can come forward with applications for relief, if a special circumstance arises which puts it clearly at risk. The Board has promptly responded to such requests from other applicants in the past. There is no reason to expect that the Board would not deal fairly and promptly with Hydro One on these projects should significant issues arise in the future.

Hydro One's request for special regulatory treatment for these designated projects is denied. In reaching this decision, the Board is not ruling out providing incentives for future projects where there is a compelling case.

6.2 NIAGARA REINFORCEMENT PROJECT

Hydro One was granted approval by the Board in July 2005 to construct the NRP and construction began shortly thereafter. As the result of a land claim by aboriginal peoples and the occupation of a portion of the lands necessary for the completion of the last two kilometers of the project, the project has been frustrated, pending a multi-lateral resolution of the underlying land claim issues.

CCC, SEC and VECC supported some form of relief regarding the NRP, while AMPCO and Energy Probe were of the view that the project should be accorded conventional ratemaking treatment.

SEC submitted that Hydro One should be allowed to expense, rather than capitalize, the AFUDC associated with the project. CCC suggested that Hydro One should be allowed to expense AFUDC for NRP for 2007 and 2008 only. VECC submitted that the Board could consider allowing AFUDC associated with the NRP to be expensed as opposed to capitalized – effective January 1, 2007. If Hydro One required additional relief prior to the project being completed and in-service, then a specific application should be brought before the Board seeking the same.

The common rationale was that, as a result of factors beyond its control, Hydro One has been prevented from placing the asset in service. All but a very short span of the project has been completed, and the overwhelming majority of the funds needed to complete and make serviceable the reinforcement have been expended. The respective positions of these intervenors reflect their assessment that this is an exceptional circumstance requiring a special regulatory response.

PWU also supported relief on the NRP and advised that the Board should focus on the substantive issues underlying the request for special treatment rather than the question of whether or not the NRP fits into the category of the other three designated projects.

Energy Probe took the position that the appropriate course is to disallow recovery of any NRP costs from ratepayers until the project is in service. Once in service, ratepayers should have to pay all costs, except those incurred from the time the Province bought the land in Caledonia until the project is placed in service.

AMPCO was of the view that as Hydro One had asked that the NRP be considered a supply mix project, it should receive the same treatment as the other designated projects.

Board Findings

The Board's role is to make decisions that are in the public interest and to determine an appropriate balance between the interests of the regulated utility and consumers. The Board agrees that special regulatory treatment is appropriate for the NRP because a recognizable risk has materialized out of the land claim dispute in Caledonia, the resolution of which is beyond the control of Hydro One.

In determining the special relief, it is important to take into consideration all aspects of this project.

Hydro One brought an application to the Board in 2004, requesting approval to proceed with this project. Hydro One's decision to initiate the NRP was not the result of OPA planning. In that 2004 application, Hydro One did not provide what the Board considered to be a sound economic rationale for the NRP. As such, the Board decided that Hydro One would be required to provide an acceptable economic justification in the future before the project costs could be recovered from ratepayers.

Hydro One has now spent $97 million on this project and the Board has received the required updated economic rationale in this application. It is not known if the project will eventually be completed, if it will come into service with a different route and additional costs, or if it must be abandoned and written off. The Board is of the view that it would not be in the public interest to shift the entire financial burden of an asset that is not in service to consumers as requested by Hydro One.

However, Hydro One faces carrying costs for these expenditures and the Board agrees with VECC and CCC that a compromise is appropriate. As CCC, VECC and SEC suggested, the Board has decided to allow Hydro One to expense – rather than capitalize – the AFUDC, or carrying costs, associated with the project based on the actual expenditures made to date. While CCC and SEC suggested it should be limited to the test years, the Board agrees with VECC in that it should be effective January 1, 2007, with no explicit time limit as it remains uncertain when the Caledonia dispute will be resolved. If Hydro One requires additional relief prior to the project being completed and in-service, it is free to bring an application seeking such further relief.

7. HYDRO ONE TRANSMISSION ROE AND CAPITAL STRUCTURE

Return on Equity (ROE)

Hydro One Transmission's revenue requirement for the year 2000, the last time the Board conducted a cost-of-service review of the transmission business, was based on a return on common equity ("ROE") of 9.88%. The Company is requesting an increase to 10% in 2007 and 10.25% in 2008.

Hydro One provided evidence in support of its request through Ms. Kathleen McShane of Foster Associates, who initially argued that an ROE of 10.5% in both 2007 and 2008 was appropriate for Hydro One Transmission. In updates of February 23, 2007 and March 1, 2007, Ms. McShane revised her recommendation on the basis that prevailing market conditions warranted lower ROEs of 10.0% in 2007 and 10.25% in 2008.

Ms. McShane's study made use of the equity risk premium, discounted cash flow and comparable earnings tests. Ms. McShane took the position that her recommendation was demonstrably reasonable in light of returns allowed for Hydro One Transmission's U.S. peers (range of 10.5%-12.5%), with whom she submits Hydro One would have to compete for capital to finance close to $2 billion in transmission-related capital expenditures in the 2006-2008 timeframe, and potentially similar levels for the several subsequent years.

CCC and VECC provided evidence through Dr. Laurence Booth of the University of Toronto, who took the position that a fair ROE for Hydro One Transmission would be approximately 7.50%, including a 50 basis point cushion. Dr. Booth submitted that most of Hydro One Transmission's risk comes from its rate design and the amount of debt financing, not its underlying business risk. Dr. Booth saw underlying business risk to be minimal for Hydro One and most regulated utilities in Canada.

The *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* of December 20, 2006 (the "Cost of Capital Report") incorporates an ROE methodology that, when applied to Hydro One Transmission, produces ROEs considerably lower than the levels proposed by Hydro One and somewhat higher than the level proposed by Dr. Booth. Based on an answer to an undertaking provided by Hydro One, application of the Board's distribution formula to Hydro One Transmission would produce an ROE of 8.53% in 2007 and 8.64% in 2008.

Capital Structure

Hydro One Transmission has a current deemed capital structure of 60% debt, 4% preference equity, and 36% common equity. It is requesting Board approval for a more favourable deemed capital structure of 56% debt, 4% preference equity and 40% common equity.

Hydro One provided evidence in support of its proposed capital structure, again by Ms. McShane, who argued that Hydro One's proposed capital structure was justified in light of its need to maintain an 'A' bond rating. Ms. McShane stated that this bond rating was critical in light of Hydro One's need to access debt markets to finance extraordinary capital expenditures, the more limited market for BBB debt, and the lesser ability of BBB-rated companies to access the long-term (30-year) debt market.

CCC and VECC provided evidence by Dr. Booth on this matter, who recommended that the Board should reduce Hydro One Transmission's allowed common equity ratio to 34%, with a 66% debt ratio. Dr. Booth noted that his recommended common equity ratio was 1% higher than that imposed on the Alberta transmission companies regulated by the Alberta EUB. During his examination-in-chief, Dr. Booth stated that he viewed transmission assets as the lowest risk regulatory assets in Canada, mainly because transmission is a natural monopoly and an essential component in the distribution of electricity. Dr. Booth also noted that Hydro One had the highest bond rating of any regulated utility in Canada. The Board notes that while Hydro One owns over 97% of the transmission system in Ontario, it is not, strictly speaking, a “monopoly”.

The Cost of Capital Report incorporates a capital structure policy for distributors of 60% debt and 40% equity. This is in line with Hydro One Transmission’s presently approved deemed capital structure.

Transmission versus Distribution Risk Differentials

In the course of this proceeding, Board staff retained Professors Fred Lazar and Eli Prisman of York University to undertake a study of whether or not there is a determinable risk differential between Hydro One’s distribution and transmission businesses that would justify differences in the allowed capital structures and cost of capital for the respective businesses.

Professors Lazar and Prisman concluded that “at this time, the results are too mixed, and most often statistically insignificant to reach any conclusion other than to award the same ROEs for both the Transmission and Distribution segments of Hydro One.”

Ms. McShane took a similar view noting that the difference in the level of risk between Hydro One Transmission and Distribution is not material enough to distinguish between the two in terms of either recommended capital structure or return on equity.

Dr. Booth expressed the view that Hydro One Transmission is of lower risk than Hydro One Distribution. During his cross-examination, Dr. Booth stated that he would be amenable to the use of the Board’s distribution rate of return mechanism to set Hydro One Transmission’s ROE, but only on the basis that the Board adjust for Hydro One Transmission’s lower risk through a lower common equity ratio.

Cost of Debt and Preference Shares

Hydro One provided its derivation of the forecast yields for each of the debt issues anticipated for 2007 and 2008, which were based on forecast Government of Canada yields for 5, 10 and 30 year debt with a Hydro One spread applied to them.

Although Ms. McShane updated her evidence on February 23, 2007 and March 1, 2007, and concluded that prevailing market conditions justified a lowering of her ROE recommendation, Hydro One did not update its debt and preference share costs to reflect the changes in market conditions that had occurred since its evidence had been filed in September 2006.

During cross examination, Hydro One acknowledged that it had not updated these costs and had issued new 30-year debt in March of this year. The Company acknowledged that there would be a difference between the cost of that new debt compared to the cost of debt assumed in the evidence. Specifically, the coupon rate of the 30-year debt assumed in the evidence was 5.53%, but the new debt had been issued at a coupon rate of 4.89%.

Hydro One explained that the reason it had not updated these costs while updating its ROE estimate was that the impact of any such update would be far more significant on the ROE than it would be on the cost of debt, as the cost of debt is based on a full portfolio of outstanding bond issues that incorporate placements going back a number of years. Also, Hydro One stated that it viewed the cost of debt as but one of a bundle of assumptions embedded in its Application, and it did not propose to revisit the full suite of its planning assumptions as the revision of some may have been more favourable to one stakeholder, while the revision of others may have been more favourable to another.

Treatment of Designated Projects – Impact on Capital Structure/ROE

Ms. McShane's initial evidence on ROE was submitted with the presumption that three designated capital projects would receive the special treatment applied for. The NRP was not initially included among these projects or as part of her assumptions.

Hydro One subsequently updated its evidence to include the NRP in its request for special treatment of the designated projects; however Ms. McShane's evidence update did not make any reference to this apparent reduction in Hydro One's risk profile.

During cross-examination Ms. McShane was asked about the impact on her recommendations if Hydro One's request for the special designated project treatment was denied. She stated that the ROE calculation would have to be adjusted upward by 25 to 35 basis points, or alternatively that a two-and-a-half to three percentage points increment in the equity ratio would be necessary. Ms McShane noted that her preference was for an adjustment to the equity ratio.

The Board's consideration of the proposed treatment of the designated projects, including the NRP, is dealt with in Chapter 6 in this Decision.

Board Findings

Hydro One asserted that its proposed increase in ROE is necessary to enable it to access capital markets effectively, and to borrow the very large sums needed to fund the expansion and reinforcement of the transmission system at interest rates that are as low as possible.

Access to these markets, and the costs of borrowing, are often seen to be dependent on the opinions expressed by various bond rating organizations. One of the key factors used by these agencies to assess the credit-worthiness of a borrower is the adequacy of its ROE in light of the business risk associated with the borrower. If the ROE is seen to be low given an entity's business risk, the cost of borrowing will rise to account for it. If the disparity is too great between the ROE and the inherent business risk, funds may not be available at all.

In this way, the Company's proposal for an increased return on equity, and an increase in the equity portion of its deemed capital structure, is bound up in many of the other proposals forming part of this rates proceeding.

It is also true that the comparative risk faced by the transmission business of the Company was an overarching theme of this Application. The Company sought to limit or eliminate the regulatory risks it is facing. Hydro One was concerned that the Company would not be granted recovery for expenditures prudently incurred. This is seen in the proposals for the designated projects, and in the assurances requested for portions of the capital projects budget, and in the Company's RRAM proposal.

To consider the Company's proposal, it is necessary to consider the riskiness of its operating environment, the perception of that environment by market analysts, and the appropriateness of the Board's methodology in establishing the appropriate ROE and capital structure.

As the operator of the vast majority of the transmission system in the province, the Company is uniquely capable, and uniquely positioned, to make a wide range of informed decisions respecting system growth and reinforcement. The ratepayer is entitled to expect that the Company makes careful, engineering-based plans, founded on its best judgement as to what the system needs.

Where line connection enhancements are made, the TSC provides a formulaic approach directed to assessing the prudence of a project, and the extent to which those directly benefited by the project are required to contribute capital. This serves to limit the exposure of the transmitter to risk. Although the same formulaic methods do not exist to assess prudence and cost recovery for large capital projects, Hydro One has ample opportunity to address these issues in Leave to Construct applications and rate cases.

A utility which has followed reasonable engineering and financial practice, and has applied the TSC appropriately, is unlikely to be denied recovery of prudently incurred costs. Similarly a utility which is confronted with unusual circumstances is unlikely to be denied relief when events out of the utility's control occur. Indeed, the response of the Board and the intervenors to the Company's dilemma respecting the NRP is evidence of a regulatory approach in the province that is flexible and responsive. This positive regulatory environment is noted in one of the bond rating agency reports.

The Board recognizes that some of the projects the Company becomes involved in are very large, both in terms of their related costs, and their potential impact on the effectiveness of the overall provision of electricity to the province's residents and businesses. It is understandable that the Company has concerns respecting its ability to recover the very large sums that it commits to such projects; however, the Board cannot discern any significant risk for the Company that it will be unable to recover prudently incurred costs.

Under the concept of just and reasonable rates, the Company has a reasonable and enforceable expectation that its prudently incurred costs will be recovered in a timely fashion. This includes an expectation that in considering the prudence of expenditures, the Board will assess the Company's judgement in light of the circumstances prevailing at the time the expenditure is made, and without the distraction of hindsight. The Company's prudence should be adjudicated on the basis of what it knew or ought to have known at the time the expenditure was made, not on the basis of subsequent events or conditions, which may have the effect of making the expenditure appear to be unwise.

There is always a risk that if the Company fails to use good judgement in formulating its plans, or otherwise incurs costs imprudently, it will not be authorized to recover such costs. That is a risk that the Company must bear on its own. No responsible regulator can protect a utility from imprudence, poor judgement or laxity. Nor, to be fair, does Hydro One appear to be asking for protection from these.

The evidence respecting the observations of the bond rating services suggests that they are much more confident than the Applicant in the regulatory regime governing the company's operations. This was particularly evident in the examples cited during the cross-examination of Ms. McShane by counsel for CCC.

One analytical tool useful in determining the appropriate ROE and deemed capital structure lies in assessing the extent to which the transmission business can be considered to be more or less risky than the distribution business. The Board's recent consideration of cost of capital in the Cost of Capital Report is of assistance in determining an appropriate ROE and capital structure for the applicant's transmission business.

The Board has examined the fundamentals of its ROE methodology on a number of occasions in the recent past. The Cost of Capital Report is only the most recent example. In each case, the Board's use of its current methodology has been confirmed.

The Cost of Capital Report was generated to inform the Board with respect to the appropriate ROE and capital structure for the local distribution companies, including Hydro One in its operation of a substantial distribution network. It follows that a consideration of the relative risks as between the transmission business and the distribution business should inform a consideration of the appropriate ROE and deemed capital structure for the transmission business.

Importantly, most of the experts providing evidence in this case were unable to conclude that there was any material difference in the level of risk between the distribution and the transmission undertakings. Dr. Booth alone suggested that transmission was less risky, and therefore should be subject to a lower overall ROE.

With respect, Dr. Booth's view seemed to be analytical, and not data based. He referred to the approach taken by the Alberta Board in the case of Altalink, a comparator that was not demonstrated to be apt.

It is the Board's view that there really is no convincing quantitative evidence before us which suggests that transmission is more or less risky than distribution. It is true that distribution has greater and more immediate exposure to the possibility of bad debts. On the other hand, in absolute terms, the transmission system involves very large capital projects of significant complexity, which can be subject to delay in completion, and consequential delay in expected revenues. On balance, the Board concludes that the evidence before us does not provide a basis upon which we can make a finding that there is any meaningful difference in risk as between distribution and transmission.

The Company is in a unique position compared to other utilities in the province. It alone among all of the utilities in Ontario operates a major transmission business and an equally large distribution business. If the Company believes that there is a significant risk differential between its two business segments, it should have been able to present much more convincing evidence respecting the relative risks. The fact that it did not is telling.

It follows that the ROE for the transmission arm of the company should not enjoy a different ROE than that governing its distribution business.

Accordingly, the Board finds that the ROE formula for electricity distributors, as documented in the December 20, 2006 Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation Mechanism, shall be applied to Hydro One Transmission. The Board has determined that Hydro One's ROE shall be derived based on an application of the Board's formula as of January 1, 2007, using December 2006 *Consensus Forecasts* and Bank of Canada data. This should result in an ROE of 8.35% for both 2007 and 2008.

The Board notes that all of the consumer intervenor groups were receptive to the use of the Board’s distribution formula for setting ROE, although most also argued that Dr. Booth’s lower recommended common equity ratio should be applied in establishing Hydro One Transmission’s capital structure. However, as has been discussed, the Board has not been presented with any convincing quantitative evidence in this proceeding which suggests that transmission is more or less risky than distribution. Accordingly, the Board will also apply the distribution capital structure to Hydro One Transmission.

The Board has further determined that Hydro One’s debt costs will not be updated. The Board notes the comments of some intervenors that the Board should require Hydro One to update its forecast debt costs, as is done for the regulated natural gas utilities. The Board notes that in recent gas proceedings where this has been done, it has usually arisen out of rates agreed to by the respective parties and included in the Settlement Agreements. In the absence of such a settlement on this issue in this proceeding, the relative magnitude of the amounts involved, and the uncertainties surrounding changes in interest rates and Hydro One’s financing plans, the Board is not convinced that the cost of debt should be updated and will use the rates contained in Hydro One’s application for the purpose of rate-setting.

8. DEFERRAL ACCOUNTS

8.1 ONTARIO ENERGY BOARD COST ACCOUNT

Hydro One has used this deferral account to capture the excess of OEB cost assessments during the past several years over the amount included in Hydro One's last approved revenue requirement. The account also includes capitalized interest. Hydro One requested Board approval of the balance of the account and its disposition over four years.

The account was established by Hydro One in 2004. The amount charged to the account in that year, $4.6 million, apparently included amounts dating from 2000.[29] The account balance was $4.8 million at the end of 2005, $7.1 million at the end of 2006, and $7.9 million at April 30, 2007.

The balance of the account and its disposition were settled issues in the Settlement Proposal but the settlement was not accepted by the Board.[30] In its Settlement Decision, the Board instructed Hydro One to provide additional evidence to establish why the Company should recover such costs, given that it did not have a Board-approved deferral account at the time the costs were being incurred.

Hydro One provided a copy of a December 2004 letter to Board staff indicating the Company's intention to implement deferral accounts and practices for tracking OEB costs, similar to those approved by the Board for use by electricity distributors. Hydro One also stated that since 2004 it has consistently included the account in its quarterly reporting, pursuant to the Board's Recordkeeping and Reporting Requirements.

[29] Tr. Vol. 7, p. 178, lines 11 to 15.

[30] EB-2006-0501, Settlement Proposal Decision, April 18, 2007, p. 6.

There is no evidence that the Board's staff acknowledged Hydro One's December 2004 letter or that the Board otherwise approved the deferral account.

Hydro One's position is that OEB costs affect its transmission and distribution businesses in an equivalent manner and it is appropriate for both businesses to maintain a deferral account for these costs. With respect to the lack of approval, Hydro One stated that "the failure to establish an official deferral account was an oversight arising out of a misunderstanding between the OEB Staff and the Applicant. Under those circumstances, Hydro One now asks that an official deferral account be established." [31]

Board Findings

The Board cannot accept that the balance in this account should be recovered from ratepayers. Although, as Hydro One suggests, there might have been a misunderstanding, the fact remains that the account has not been approved by the Board.

The Board might have considered approving recovery of the account had the balance resulted from an extraordinary variation in expenses and if the balance were large enough that non-recovery might be a financial burden on the company. In the Board's view, that is not the case here. At least six years have passed since the Board last examined Hydro One's transmission revenue requirement. Over that period, the revenues and expenses of the transmission business have varied, sometimes significantly, from the amounts approved in the last rates case. In a business with annual revenues in excess of $1.2 billion, it does not seem particularly noteworthy that the cumulative variance in a single expense line over that time is $7.9 million (including capitalized interest). The swing in transmission revenues in any year due to weather and other factors has been many times larger than that.

[31] Hydro One Reply Submission, June 13, 2007, p. 57.

As noted in the following section, an earnings sharing mechanism was in place in 2006. Although the Board disallows recovery of the OEB cost deferral account balance, it will permit Hydro One to deduct the growth in the account in 2006 ($2.3 million) from 2006 earnings in calculating excess earnings.

8.2 2006 EARNINGS SHARING MECHANISM

Calculation of Excess Earnings

The earnings sharing mechanism (ESM) was established by the Board in its February 21, 2006 decision on EB-2005-0501. In that decision, the Board determined that excess earnings of Hydro One’s transmission business from January 1, 2006 until new transmission rates are implemented should be shared equally by ratepayers and the Company. Earnings for 2006 were to be determined from actual results as shown in Hydro One’s 2006 audited transmission business financial statements. In its Partial Decision and Order dated March 30, 2007, the Board approved a 2007 Revenue Difference Deferral Account, which had the effect of terminating the ESM as at December 31, 2006.

In its pre-filed evidence, as updated April 20, 2007, Hydro One calculated total excess after-tax earnings for 2006 of $37.5 million, 50% ($18.7 million) of which would be for the account of ratepayers. In calculating that amount, Hydro One decided to exclude two 2006 income statement credits aggregating $30.2 million, after tax:

- A tax benefit of $16.4 million that was recognized in the first quarter of 2006. According to the 2006 audited financial statements of Hydro One’s transmission business, the benefit related to a “recovery of PILs from prior years following a successful appeal allowing a deduction for certain overhead costs that had been previously capitalized.”

- A $21.6 million recovery in 2006, recorded as a reduction of OM&A expense, of property taxes for the years 1999 to 2005 inclusive. The after-tax impact of this item was $13.8 million.

In its final argument, Hydro One indicated it would increase its calculation of excess earnings as a result of reallocating expenses from its transmission business to its distribution business. This adjustment was made after discussion in the hearing about how to apply the requirements of the Board's February 21, 2006 decision that established the ESM.[32] In its reply argument, Hydro One noted that this reallocation would increase excess pre-tax earnings by $9.5 million ($6 million after tax).

Hydro One submitted that it is appropriate to exclude the two items from income because they resulted from the resolution in 2006 of issues that arose in prior years. In support of its position, Hydro One cited a 2004 Board decision on an Enbridge Gas Distribution earnings sharing mechanism,[33] in which the Board directed Enbridge to exclude from its calculation of excess earnings the write-off in 2004 of a non-recoverable receivable (the balance in a deferral account established in an earlier period). The decision stated: "Earnings determinations should be unfettered by differing accounting treatments and related reporting inclusions and exclusions."

Intervenors disagreed with the exclusion of the two items from the calculation of 2006 excess earnings. They submitted that it is clear from the Board's decision on EB-2005-0501 that the excess earnings should be calculated from the unadjusted 2006 audited financial statements. Hydro One submitted that the intervenors who oppose Hydro One's adjustments are reversing the position they took when they supported the exclusion of expenses from Enbridge's earnings sharing mechanism in 2004. SEC argued, however, that the Board's intent in the 2004 Enbridge Gas Distribution decision

[32] In its decision on EB-2006-0501, the Board ordered Hydro One "to report revenue changes for the 2006 rate year resulting from the Board's decision on cost allocation in RP-2005-0020/EB-2005-0378. The [cost allocation] report will be reviewed with the objective of crediting the resultant cost allocation adjustment to transmission customers in the 2007 rate application." (p. 6)

[33] RP-2003-0203/EB-2004-0468, Decision With Reasons, November 24, 2004.

was simply “to avoid the absurd result whereby an amount previously adjudged to be non-recoverable from ratepayers would become partially recoverable as a result of the earnings sharing mechanism”.[34]

Proposal to Treat Excess Earnings as a Capital Contribution

Hydro One proposed that the pre-tax amount of the ratepayers’ share of the 2006 excess earnings be treated as a capital contribution (that is, the amount would be treated as a reduction of rate base) to be applied against two capital projects that under development.[35] Ratepayers would receive the benefit of the excess earnings through reduced charges in the future for both depreciation and return on capital.

The capital contribution treatment was proposed by Hydro One when the Board first established the ESM in February 2006. The Board did not accept the treatment at that time but indicated that Hydro One could bring the matter forward at the time of disposition of the account balance.

Hydro One cited some U.S. cases as precedents for the capital contribution treatment. In response to concerns that its capital contribution proposal creates intergenerational equity issues (by stretching out the return of the excess earnings to ratepayers over several decades), Hydro One suggested it could credit the excess earnings against capital projects with much shorter useful lives, such as the Cornerstone IT project.

Intervenors were opposed to the capital contribution approach. They objected to ratepayers, who overpaid for transmission service in 2006, receiving the benefits over a protracted period starting in 2009 when the two capital projects are to be in service. AMPCO also argued that capital contribution mechanisms are designed to protect ratepayers who will not benefit from projects requested by specific customers. In

[34] SEC Final Argument, p. 44.

[35] The projects are the Southern Georgian Bay Reinforcement and the Hurontario Switching Station. The aggregate estimated cost of the projects is $135 million. Both developments are expected to be in service in 2009.

AMPCO's view, such mechanisms are inappropriate for returning overearnings to ratepayers.

The intervenors argued that excess earnings should be returned to ratepayers over a much shorter period, either over two years (2007 and 2008) or over four years (the period over which other Hydro One deferral accounts are cleared). CCC, SEC, and VECC supported netting the balance against the RDDA balance (see section 8.3 below) and including the net amount in the revenue requirement over either two or four years.

Board Findings

The Board does not agree with the proposal to exclude the two income items from the calculation of 2006 excess earnings. The Board finds that the EB-2005-0501 decision which established the ESM is clear that the 2006 audited income statement (called the Statement of Operations by Hydro One) is the basis for the calculation. There is nothing in that decision that suggests Hydro One was to have discretion to exclude any income or expense. The section on page 10 of that decision entitled, "By what mechanics should excess earnings be established?" sets out a mechanical approach to the calculation that does not provide for adjustments for "prior period" or "non-recurring" items. In fact, that section states: "The following items will be sourced from the audited financial statements (Transmission): Net Income (actual, not normalized for weather) – from Statement of Operations."

Although the two items in question result from resolution of issues that arose in prior periods, neither item apparently qualified as a prior period adjustment under generally accepted accounting principles; had they so qualified, they would have been omitted from the 2006 audited income statement and included in restated prior period financial statements.

The Board does not agree with Hydro One that the 2004 Enbridge Gas Distribution decision is a relevant precedent. The decision that established the Hydro One ESM is so clear on how the calculation is to be done that there is no need to seek guidance from any other source. In addition, as noted by SEC, the 2004 Enbridge decision concerned the write-off of a regulatory balance that apparently had been determined to be uncollectible from ratepayers, so it would make little sense to require ratepayers to absorb some of that amount thorough an ESM.

The Board will require Hydro One to recalculate the amount of excess 2006 earnings without exclusion of the two income items. As noted in section 8.1 on the OEB cost account, the Board will also permit Hydro One to deduct the growth in that account in 2006 in determining excess earnings.

The Board does not accept the capital contribution approach proposed by Hydro One. In the Board's view, it is important that overearnings be returned to customers as soon as possible; the capital contribution approach results in an inappropriately long "refund" period. That is true even if the excess earnings were to be credited against a capital project with a shorter life than a transmission station. The Board finds that the balance in the ESM account should reduce Hydro One's revenue requirement at the first available opportunity, which is the revenue requirement for the years 2007 and 2008.

8.3 2007 REVENUE DIFFERENCE DEFERRAL ACCOUNT

This account was approved by the Board in a March 30, 2007 Partial Decision and Order. It is intended to capture the difference (positive or negative) between (a) revenue determined using the rates resulting from this proceeding, and (b) revenue determined using currently approved transmission rates. The revenue difference is to be calculated for the period from the effective date of Hydro One's new revenue requirement to the date on which new uniform transmission rates are implemented. The Board did not make a decision on either the effective date or the implementation date in its March 30, 2007 Partial Decision and Order. The Board also did not decide whether the revenue amounts should be based on actual or forecast load.

During the hearing, Hydro One witnesses presented the Company's proposal on the calculation of the balance in the Revenue Difference Deferral Account ("RDDA") and the manner in which new rates should be implemented (Exhibit L7.1). Hydro One proposed that:

- The new revenue requirement resulting from this proceeding should be effective January 1, 2007;
- New uniform transmission rates should be implemented November 1, 2007; and
- The RDDA balance for the 10 months to October 31, 2007 should be calculated based on forecast load, not actual load.

Hydro One set out two options for making the rate change. The first option, and Hydro One's preference, is to implement a single rate change on November 1, 2007 to collect the approved 2007-2008 revenue requirement for the next 14 months and the balance in the RDDA. The second option would be to have two rate changes – one on November 1, 2007 and a second on January 1, 2008.

Three intervenors (CCC, SEC, and VECC) argued that the effective date of the new revenue requirement should depend on whether it is higher or lower than the revenue Hydro One would earn at current rates. If the new approved revenue requirement is lower, all three supported an effective date of January 1, 2007. If the new requirement is higher, all three advocated a later effective date. CCC and VECC supported May 1, 2007, the date Hydro One requested in its initial application. SEC submitted that a higher revenue requirement should only become effective when new uniform transmission rates are implemented. The intervenors acknowledged the assymetrical nature of their recommendations but submitted that the result would be fair given that Hydro One filed its application less than four months before the beginning of 2007. SEC explained its position this way:

> SEC understands that at first blush that position may seem contradictory or even unfair to the Company. However, it is the applicant that controls the timing of rate applications. Accordingly, the Applicant should be at risk of not recovering its revenue deficiency in the event it does not file in time to have its rates in place at the beginning of the test year. It is not acceptable, however, for the Applicant to risk the ratepayers' money by filing in such a way as to ensure that a portion of a rate reduction is not paid to ratepayers as a result of the timing of the application.[36]

With respect to the calculation of the balance in the RDDA, AMPCO supported using actual load while CCC supported using forecast load. Both intervenors supported the first rate implementation option, a single rate change on November 1, 2007. VECC argued that Hydro One should be directed to come forward with a detailed implementation plan once the 2007-2008 revenue requirement is approved.

In reply, Hydro One stated that a January 1, 2007 effective date is simple to implement. It submitted that it was not possible for the Company to file an application any earlier than September 2006. It also said that the intervenors' request for different effective dates depending on the amount of the new revenue requirement was not fair and balanced.

Board Findings

This is the first application by Hydro One Transmission in many years and there is no well established practice for determining the effective date of a new revenue requirement for this business.

The Board acknowledges the intervenor comments that there was no prospect of new transmission rates being implemented on January 1, 2007 given that the application was filed in mid-September 2006. The Board notes that the pooled uniform rates used for electricity transmission in Ontario necessarily will result in a longer period between the application date and the implementation of new rates than is the case in gas and

[36] SEC Final Argument, p. 39.

electricity distribution. For this reason, the Board is not as concerned as some of the intervenors about the relatively short period between the timing of Hydro One's application and its request for a January 1, 2007 effective date.

The Board has determined that Hydro One's new revenue requirement should be effective January 1, 2007. This approach aligns the start date of the new revenue requirement with the beginning of the 2007 test year for which Hydro One filed considerable evidence and analysis. A later date would effectively result in three different revenue calculations for the 2006-2007 period (2006 – revenue based on current rates, adjusted for the ESM; 2007 up to effective date – revenue based on current rates; 2007 after effective date – revenue base on new rates).

The Board is also not supportive of selecting an effective date that is always to the disadvantage of the Applicant, which is what several intervenors advocated (that is, an early date if the revenue requirement falls but a later date if the revenue requirement is increasing). The Board agrees with Hydro One that this would not be fair and balanced.

The Board accepts the use of forecast load to calculate the RDDA balance since that is consistent with the way new rates will determined. The Board also agrees with the first option to rate implementation (a single rate change targeted for November 1), which is a relatively simple approach.

9. LOAD FORECAST

Rates for each of Hydro One's three transmission charge pools – network, line connection, and transformation – are based on a customer's coincident or non-coincident peak load. Thus, a peak load forecast is required to translate the Board-approved revenue requirement for 2007 and 2008 into rates. Customer rates per kW of load are directly affected by the forecast used to derive the rates.

Table 7 shows Hydro One's forecast of average 12-month peak load for the test years for Ontario as a whole and for Hydro One's individual charge pools. Hydro One's estimates of the impact of embedded generation and conservation and demand management (CDM) are also shown.

Table 7: Hydro One Load Forecast

12-month average peak load in MW	ONTARIO DEMAND	HYDRO ONE CHARGE POOL		
		Network	Connection	Transformation
2007				
Forecast before embedded generation and CDM	22,507	22,023	20,892	17,962
Impact of embedded generation	(140)	(140)	(10)	(10)
Impact of CDM	(1,085)	(1,055)	(1,007)	(866)
Net forecast load	21,282	20,828	19,875	17,086
2008				
Forecast before embedded generation and CDM	22,730	22,241	21,099	18,140
Impact of embedded generation	(165)	(165)	(10)	(10)
Impact of CDM	(1,239)	(1,203)	(1,150)	(988)
Net forecast load	21,326	20,873	19,939	17,142

Source: Pre-filed evidence, Exhibit A, Tab 14, Schedule 3, page 19.

Forecast peak load, before the impact of embedded generation and CDM, is based on several methods (econometric models, end-use models, customer surveys, hourly load shape analysis) and is “weather-normal”, that is, the forecast assumes typical weather conditions based on data from the past 31 years.

In the hearing and in final argument, intervenors focussed on two load forecasting issues. The first related to the accuracy of Hydro One’s peak load forecast and the weather normalization methodology used by the Company. The second issue concerned the amount by which weather-normalized peak load should be reduced in respect of CDM activities. None of the intervenors challenged Hydro One’s adjustment for embedded generation or the economic assumptions underlying the forecast, such as forecasts of GDP, housing starts, and population growth.

9.1 WEATHER-CORRECTED FORECAST DEMAND

AMPCO noted that Hydro One’s weather-corrected peak load has been less than actual peak load for each of the last eight years. On average, the actual peak exceeded the weather-adjusted peak by 438 MW per year over that period. AMPCO argued that either the process is flawed or the definition of normal weather is no longer applicable. AMPCO also noted that monthly maximum peak demand in each of the first five months of 2007, as shown in IESO publications, exceeded Hydro One’s forecast.

Hydro One disagreed with the conclusion drawn by AMPCO from the eight years of data. The Company stated that weather is fundamentally unpredictable and past data shows that there can be years of consistent positive or negative differences between forecast and actual load. The Company stated that over the 20 years from 1982 to 2001 the average difference between actual and weather-adjusted monthly peak demand was just 17 MW, which Hydro One says supports its contention that its methodology is sound and unbiased.

Hydro One stated that its weather normalization methodology is consistent with the industry standard and is the most commonly used approach by electricity transmitters and distributors.

AMPCO and VECC commented on the differences between the weather-normal forecast of monthly peak demand published by the IESO and Hydro One's forecast. Forecast demand for each of the 18 months from January 2007 through June 2008 is substantially higher in the IESO forecast. Hydro One indicated that the two forecasts are based on different assumptions, approaches, and definitions that arise from the different purposes of the respective forecasts. In their arguments, AMPCO and VECC disagreed with some of the examples of differences cited by Hydro One.

AMPCO recommended that the Board direct Hydro One to set its charge determinants using the IESO's weather-normal maximum hourly demand forecast. VECC submitted that the unexplained difference between the IESO and Hydro One weather-normal forecasts is growing. However, VECC did not recommend that the Board order Hydro One to use the IESO's forecast.

Board Findings

The Board does not have sufficient evidence to agree with AMPCO's assertion that Hydro One's weather-normalized forecasts have shown a "clear and growing bias" and that the weather-normalization methodology is flawed. The Board acknowledges that Hydro One's weather-normalization method has been applied consistently over the years and is similar to the methods used by most North American utilities. The Board accepts Hydro One's weather-normal peak load forecast for 2007 and 2008 (before the effects of CDM). The Board is, however, convinced that the weather-normalization issue needs further study given the well-publicized concerns about global climate change and the apparently increased occurrence of so-called "extreme weather events" in recent years.

The Board also does not have sufficient evidence to accept AMPCO's recommendation that Hydro One use the IESO weather-normal forecast to set its rates for 2007 and 2008. The IESO forecast was not examined in the hearing in any detail, and the Board has limited understanding of the assumptions and definitions that underpin that forecast. On the surface at least, the two forecasts appear to be directed at essentially the same thing, namely weather-normalized monthly peak load. The IESO's forecasts are publicly available and apparently widely-used by electricity sector participants. Thus the Board concludes that it needs to have a much better understanding of the similarities and differences between the widely-available IESO forecast and the forecast used to set transmission rates, before it can direct the Company to adopt the IESO forecast methodology in place of its own.

Given the concerns set out in the two preceding paragraphs, the Board directs Hydro One to prepare, and to submit to the Board prior to the Company's next transmission rates case, a study of evolving weather-normalization practices of utilities and other relevant entities. The study should include a recommendation, with supporting rationale, for either retaining the current methodology or making modifications. As noted by Hydro One's counsel in final argument, the Board's current three-year business plan includes an initiative to review weather normalization methodologies. That project, which has not yet been fully defined, is intended to deal specifically with the practices of gas distributors. As such, it is not a substitute for the study that the Board is directing Hydro One to undertake.

The Board also directs Hydro One to submit a detailed comparison of its forecasting methodology and assumptions with those used by the IESO in its monthly peak load forecasts before its next rates case. That report should, to the extent possible, identify the reasons for significant differences in the two forecasts in recent years.

9.2 CDM FORECAST

Considerable hearing time was devoted to the question of how much Hydro One should reduce its estimated peak load to recognize the results of CDM activities across

Ontario. Intervenors from consumer groups submitted that Hydro One has overstated the impact of CDM for 2007 and 2008 and, therefore, the Company's peak load forecast after CDM is too low.

As shown in Table 7 above, the impact of Hydro One's proposed CDM adjustment is significant. The 12-month average peak load for each of Hydro One's charge categories is lower by approximately 5% in 2007 and 2008 due to the estimated impact of CDM. According to Hydro One, transmission rates would have to increase by 1% for every 300 MW decrease in peak load.

Hydro One's approach to the 2007 and 2008 CDM adjustment can be summarized as follows:

- The Company's peak load forecast (before embedded generation and CDM) is intended to capture the impact of natural conservation efforts that individuals and businesses undertake. According to the OPA, natural conservation "occurs when Ontarians invest in conservation on their own initiative and when the efficiency of the overall stock of equipment and appliances increases as older, less efficient stock is replaced by more efficient products mandated by Ontario's building and appliance standards."[37]

- Hydro One assumes that the government's 2007 CDM target of a reduction in peak load of 1,350 MW will be achieved. For 2008, a peak load reduction of 1,550 MW is assumed. The reductions in Table 7 are lower than these amounts reflecting the fact that Table 7 shows 12-month average peak loads, not peak load in any single month.

- Hydro One points to its success in forecasting CDM-related load reductions in 2006 as support for its forecast of the impacts in 2007 and

[37] Chief Energy Conservation Officer's 2006 Annual Report, p. 26.

> 2008. In its 2006 forecast, Hydro One reduced peak load by 675 MW for CDM. Information from the OPA suggests that program-driven CDM reductions in 2006 (i.e.. reductions not due to naturally occurring CDM) reached 635 MW by summer 2006, six per cent below Hydro One's estimate. [38]

AMPCO, CCC, SEC, and VECC took issue with several aspects of Hydro One's CDM adjustment.

First, CCC submitted that the 2007 reduction of 1,350 MW is solely based on a provincial target, one that is acknowledged by the OPA to be aggressive.

Second, several intervenors argued that Hydro One has in effect "double counted" load reductions due to natural conservation: once through its normal forecasting process and then a second time by using the full 2007 CDM target of 1,350 MW.

Third, those intervenors also argued that it is inappropriate to reduce a weather-normalized peak load forecast for demand response programs that by their nature are triggered, or become fully effective, only during periods of extreme weather.

The intervenors representing consumer groups, recommended various reductions in Hydro One's CDM adjustment. CCC recommended a reduction from 1,350 MW to 650 MW for 2007 comprised of 400 MW for the double counting of natural conservation and 250 MW for overstated results of demand response programs.

SEC argued for a 400 MW reduction for each of 2007 and 2008.

[38] The 2006 Annual Report from Ontario's Chief Energy Conservation Officer reported, at page 26, that "preliminary analysis suggests that Ontarians have reduced peak demand by 963 megawatts by summer 2006. These savings include 328 megawatts of naturally occurring conservation …" The difference in the two numbers, 635 MW, presumably is the amount of the reduction due to various CDM programs.

VECC recommended a 600 MW reduction for 2007 and a 650 MW reduction for 2008. AMPCO did not recommend a specific reduction of the CDM adjustment because its concerns about all load forecasting issues were reflected in its suggestion (referred to in section 9.1) that the Board order Hydro One to use the IESO monthly forecast.

PWU supported Hydro One's CDM adjustment. It stated that the Board should exercise caution in relying on estimates of 2006 CDM-related load reductions published by the OPA. It also argued that any adjustments are premature because the OPA is in the process of developing evaluation, measurement and verification standards for CDM programs.

Board Findings

The Board acknowledges that forecasting the impact of CDM on peak loads is not a simple task at this time. The impact and effectiveness of particular CDM programs is sometimes elusive, and hard to define with precision. Having said that, the Board is not satisfied that Hydro One's proposed CDM adjustments are appropriate. While we do not object to Hydro One starting its analysis with the provincial target of 1,350 MW for 2007, we agree with intervenors that Hydro One has double counted the impact of natural conservation. It is clear from the evidence that the OPA intends to count natural conservation in determining if the 2007 target of 1,350 MW has been met.[39] Hydro One testified that its forecast, before the CDM adjustment, already factors in natural conservation. Therefore, the Board fails to understand how Hydro One can rationalize not reducing the 1,350 MW target for estimated natural conservation.

The Board also agrees with the consumer group intervenors with respect to the impact of demand response programs. Hydro One's base forecast is weather-normal, which means that extreme weather events are excluded. It would seem logical to reduce the

[39] This is particularly clear from OPA comments submitted by AMPCO on May 24, 2007 in response to Undertaking K10.3.

impact of demand response programs, which are most effective in extreme weather situations, when adjusting a weather-normal forecast.

The Board finds that Hydro One should reduce the expected impact of CDM on total Ontario peak demand by 350 MW. This adjustment is intended to address both the natural conservation and demand response issues discussed above. The Board acknowledges that this reduction is probably at the low end of an acceptable range given that it is only marginally above the 328 MW of natural conservation for 2006 referred to in the Chief Energy Conservation Officer's 2006 annual report. The Board finds there is sufficient data to support a reduction of 350 MW but also finds there is not enough reliable data to support a larger reduction as advocated by some intervenors.

The Board directs Hydro One to recalculate the average monthly forecast peak load for each charge determinant category for 2007 and 2008 based on Ontario peak load reductions of 1,000 MW in 2007 and 1,200 MW in 2008.

CDM adjustments were also addressed in Hydro One's last distribution rates case. The Decision in that case stated: "The Board was dissatisfied with the clarity and precision of the determination of the forecast CDM and expects Hydro One to provide a more sound analysis of CDM program details and reduction objectives in future applications[40]." The Board recognizes that Hydro One's transmission application was filed not long after those comments were made. It would be unfair to expect Hydro One to have rectified all of the issues identified in the distribution case. The Board does expect, however, that the CDM adjustments to the load forecast included in Hydro One's next transmission filing will be based on a much more rigorous analysis, including, where possible, load impacts attributable to specific programs.

[40] Decision With Reasons, RP-2005-0020/EB-2005-0378, April 12, 2006, para. 2.3.9.

10. CHARGE DETERMINANTS

Hydro One proposed to continue with the status quo charge determinants for its Network, Line Connection, and Transformation Connection services. The connection-related charge determinants were settled leaving only the Network determinants as an issue. AMPCO was the only intervenor with a particular interest in changing the Network charge determinants. It submitted evidence and presented a witness panel.

The current Network charge determinant, which was approved by the Board in 2000,[41] is the higher of (i) a customer's demand in kW in the hour during a month that overall system demand is at its peak (coincident peak), and (ii) 85% of the customer's peak demand during the period 7:00 am to 7:00 pm on weekdays that are not holidays (non-coincident peak). The current charge for Network service is $2.83 per kW per month.

Before it filed its application, Hydro One consulted with stakeholders about rate design options and possible changes to charge determinants. Its application described two alternatives for the Network charge determinant that it said received the most consideration. Those were coincident peak only (that is, elimination of the 85% of non-coincident peak aspect of the calculation), and coincident demand in the hours when the system peak exceeds 90% of the monthly system peak demand. Hydro One concluded that the status quo was superior to the alternatives when judged against the following criteria – cost causality, electricity market benefits, revenue stability/security, cost shifting, alignment with precedents, and implementation issues.

Provided its revenue requirement is protected in some fashion, Hydro One should be financially neutral regardless of the charge determinant selected. But changing charge

[41] Decision With Reasons, RP-1999-0044, May 26, 2000.

determinants could shift, possibly by material amounts, transmission charges incurred by individual customers or customer groups.

AMPCO's Proposal

In its evidence, AMPCO proposed that the Network charge determinant should be a customer's peak demand during the hour when system peak demand occurs in the five months of January, February, June, July and August. This method was referred as a "five-coincident-peak" approach (5-CP). AMPCO indicated that a similar method is used by transmission owners in the PJM Interconnection in the United States, where some of AMPCO's members operate manufacturing facilities.

In its final argument, AMPCO modified its proposal to some extent and recommended that the Board direct Hydro One to do three things:

- Eliminate the second element of the current Network charge determinant (85% of non-coincident peak demand, referred to by AMPCO as the "85% ratchet").

- Work with the IESO, OPA and stakeholders to define those peak demand months of the year that are of concern to system planners, operators, and Hydro One in terms of system reliability, adequacy of supply, and the need for future peaking supply. AMPCO proposed there would be just five or six such months.

- Develop an appropriate non-ratcheted charge determinant based on the identified peak months.

In its evidence, AMPCO proposed a "balancing account" for Hydro One to mitigate the risk of revenue instability due to elimination of the "85% ratchet." Its witnesses stated that AMPCO had not yet developed the details of how to calculate the revenue differences to be included in the account.

AMPCO's rationale for changing the Network charge determinant is that the current design "is incorrect in principle and constitutes a barrier to demand response and the efficient use of the transmission system.[42]" It submitted that the 85% ratchet is inconsistent with practices in other jurisdictions. In AMPCO's view, the "ratchet" reduces (by 85%) a transmission customer's incentive to control its demand during system peak hours. AMPCO submitted few large power consumers can shift all of their consumption away from the peak weekday hours from 7:00 am to 7:00 pm. Even if such consumers shifted load away from the individual peak hour, they will only receive a 15% reduction in their network transmission charges. AMPCO also suggested that it is inappropriate to charge consumers for Network service every month of the year when total demand in many months is not material from a system planning and operational standpoint.

AMPCO asserted that its approach would increase demand response during peak periods, which would be consistent with Ontario government policy, and would reduce electricity costs for all consumers.

Opposition to AMPCO's Proposal

AMPCO's proposal was opposed by Hydro One and all intervenors who commented on the issue (CCC, EDA, IESO, SEC, Toronto Hydro-Electric System, and VECC). The intervenors submitted several criticisms of AMPCO's proposal; some of the significant criticisms are summarized below.

Intervenors argued that AMPCO presented no evidence that its proposal would avoid or defer capital spending on the transmission system. VECC noted that much of the anticipated capital expenditures on the transmission system in the near term, such as

[42] AMPCO Final Argument, p. 27.

the Bruce to Milton line, are driven by new generation projects or local area load constraints, not system-wide capacity issues.

EDA noted that in the decision which set the current charge determinants (RP-1999-0044) the Board stated:

> A rate design aimed at customer demand reduction during the system's coincident peak hours would meet the test of economic efficiency, but only if the network transmission system is generally capacity-constrained. This is not the case for the OHNC [Hydro One] network transmission system either today or in the foreseeable future. (paragraph 3.4.27)

EDA submitted that AMPCO did not provide any evidence that Hydro One's system is capacity constrained now. EDA argued that the Board's finding in RP-1999-0044 remains sound. Hydro One confirmed that the transmission system is generally not capacity constrained.

EDA suggested that the AMPCO proposal would benefit only those transmission customers with the ability to shift consumption away from the peak hours. Toronto Hydro pointed out that it and other local distribution companies (LDCs) have little or no ability to shift their demand away from the peak because LDCs have little control over when their customers consume power. They would, therefore, pay a larger share of Hydro One's Network charges.

AMPCO provided little evidence that its 5-CP method would lead even its own members to shift their demand significantly. From the evidence, it appears that only steel companies have the operational flexibility to shift a significant amount of load off peak.

AMPCO provided no evidence that its proposal would lower commodity costs for the benefit of all electricity consumers even if it is assumed that it would result in significant load shifting by large industrial and commercial consumers. VECC noted Hydro One submitted data for 2005 showing that high-priced hours in the IESO-administered electricity market were poorly correlated with transmission system peak hours. If this relationship cannot be established, the “benefits” associated with the AMPCO proposal become elusive.

AMPCO filed a 2003 Navigant Consulting study, *A Blueprint for Demand Response in Ontario*, as support for its views on the commodity price impact of its proposal. VECC submitted that the study’s conclusions on the value of demand response did not support AMPCO’s premise, in part because Navigant Consulting estimated the impact of demand response for many more hours than would be relevant under AMPCO’s 5-CP proposal. A further concern was that the study was prepared several years ago when there were few organized demand response programs in Ontario. AMPCO acknowledged that a more current study would be helpful and that “it may be that a lot of the commodity savings that Navigant talked about have been mined.”[43]

EDA submitted that AMPCO’s proposal is more complex than the status quo and noted that it is unclear how the proposed “balancing account” would work. The IESO, which is responsible for billing transmission charges for all transmitters, indicated that AMPCO’s 5-CP proposal would take a minimum of six months and cost $150,000 to make the required information system changes.

During the hearing, Board staff noted that days defined a holidays by the IESO (which calculates Network transmission charges) differ from the days defined as holidays by the Board for purposes of its Regulated Price Plan. The IESO suggested that the best approach would be to have Board staff work with the IESO to implement a consistent holiday schedule.

Board Findings

The Board finds that Hydro One should continue to charge for its Network service using its current charge determinant. It does not accept AMPCO’s recommendation that the

[43] Tr. Vol. 10, p. 142.

Board should order Hydro One to work with the IESO, OPA and other stakeholders to design a new method.

AMPCO's 5-CP proposal was not well defined and, as became evident during cross examination of its witnesses, it appeared the proposal was really more of a concept than a workable alternative to the status quo. More fundamentally, the Board is not convinced that AMPCO has made a compelling case either that the current Network charge determinant has significant defects or that its 5-CP proposal is superior.

In reaching these conclusions, the Board is not saying that it is impossible to improve on the current methodology, nor is it saying that it is not open to considering changes in the future. As the Board knows from RP-1999-0044, the proceeding in which the current approach to the Network service charge determinants was approved, designing transmission rate structures requires considerable evidence and the involvement of a wide range of stakeholders. Parties that advocate changes in how customers should pay for transmission service need to submit a strong case for change, with detailed evidence and analyses showing why the status quo has undesirable effects and is inappropriate. In the Board's view, AMPCO did not put forward that case in this proceeding.

With respect to achieving a consistent definition of "holiday," the Board agrees with the IESO that the issue need not be resolved in this proceeding. It is more appropriate for Board staff to work with the IESO to implement a consistent holiday schedule.

11. IMPLEMENTATION AND COST AWARDS

Hydro One applied for a transmission revenue requirement of $1,240 million for the 2007 test year and $1,277 million for the 2008 test year. The Board made a number of findings that will affect these amounts.

During the course of the oral hearing, Hydro One provided two options for transmission rate implementation.

Option 1, is a proposal for a single uniform transmission rate change on November 1, 2007, covering a 14 month period, including:

- An RDDA amount consisting of: [Approved 2007 Revenue Requirement x 10 month forecast volume/ forecast annual volume] **less** [2000 Rates x 10 month volume], *(revenue share adjustment is not mentioned).*
- 2007 approved revenue requirement for 2 months in 2007 (Nov. and Dec.)
- 2008 approved revenue requirement for 12 months in 2008.

Option 2, is a proposal for two rate changes, one on November 1, 2007 and one on January 1, 2008.

As noted in Chapter 8, the Board finds that a single rate change (Option 1) should be implemented by Hydro One.

Therefore the Board directs the Company to file with the Board and all intervenors of record, a draft exhibit outlining the final revenue requirements and charge determinants to reflect the Board's findings in this decision. The Company should file this exhibit within 10 days of the issuance of this decision. In addition, an exhibit should be filed which includes the calculation of the uniform transmission rates, charge determinants and revenue shares resulting from this decision. This exhibit will be used in the uniform transmission rates proceeding to establish the Ontario Uniform Transmission Rates.

Hydro One should provide a clear explanation of all calculations and assumptions used in deriving the amounts used in these exhibits. Intervenors shall have 10 calendar days to respond to the Company's exhibit. The Company should respond as soon as possible to any comments by intervenors.

Cost Awards

A number of intervenors were deemed eligible for cost awards in this proceeding. On June 26, 2007, Procedural Order No. 5 was issued directing those intervenors to file their cost claims with the Board by July 10, 2007. Hydro One was to reply to those claims by July 23, 2007 and any intervenor reply to Hydro One's submissions was to be submitted by August 1, 2007.

The following eligible intervenors requested recovery of their costs and filed cost statements: Energy Probe, VECC, CCC, SEC, Electricity Distributors Association ("EDA"), and AMPCO.

Hydro One did not comment on the cost claims submitted by the eligible intervenors.

The Board wishes to commend all intervenors for coordinating their cross-examination, which resulted in efficiencies with no perceived compromise in effectiveness. The Board awards all eligible parties (Energy Probe, VECC, EDA, CCC, AMPCO and SEC) 100 percent of their reasonably incurred costs. The precise amounts will be confirmed after a review by the Board's Cost Assessment Officer to ensure that the rates or fees claimed and disbursements do not exceed the Board's guidelines contained in the Practice Directions. Hydro One shall pay the amounts of the intervenor cost awards immediately upon receipt of the Board's cost orders.

Hydro One shall also pay the Board's costs upon receipt of the Board's invoice.

DATED at Toronto August 16, 2007.

Original signed by

Pamela Nowina
Vice Chair, Presiding Member

Original signed by

Paul Sommerville
Member

Original signed by

Bill Rupert
Member

APPENDIX 1

HYDRO ONE NETWORK INC.
2007 AND 2008 ELECTRICITY TRANSMISSION RATES

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0501

PROCEDURAL DETAILS
INCLUDING LISTS OF PARTIES AND WITNESSES

August 16, 2007

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

THE PROCEEDING

On October 17, 2006, the Board issued a Letter of Direction and Notice of Application to Hydro One Networks Inc.

The Board issued Procedural Order No.1 on November 30, 2006, establishing the procedural schedule for a number of early events prior to the oral hearing. These events included an Issues Conference on December 7, 2006, and an Issues Day on December 14, 2006;

On Issues Day, the Board heard submissions from the SEC, CCC, VECC, PWU and AMPCO.

The Board issued Procedural Order No. 2 on December 20, 2006, which included the Board's decision on the contested issues identified on Issues Day. The Issues List for the proceeding was attached to Procedural Order No. 2. The Board also directed that notice be given to all transmitters and their customers, informing them that this proceeding would deal with the issue of charge determinants. Procedural Order No. 2 also included Schedule 1, consisting of excerpts of certain findings and observations from the Distribution decision (RP-2005-0020/EB-2005-0378). A number of hearing event dates were also amended:

- Written interrogatories to the Applicant by Board staff due on December 21, 2006 and by the intervenors due on January 11, 2007;
- Written interrogatory responses from the Applicant due by January 29, 2007;
- Intervenor evidence filed by February 14, 2007; interrogatories on this evidence by February 23, 2007 and responses due on March 2, 2007;
- Applicant evidence update on February 23, 2007 with a related technical conference on the update on March 6, 2007;

- A Settlement Conference was set for March 26, 2007 and the Settlement Proposal Hearing set for April 10, 2007;

- The oral hearing set to begin on April 19, 2007.

The Board issued Procedural Order No.3 on March 2, 2007, amending the start date for the oral hearing to April 23, 2007.

In a letter dated February 14, 2007 Hydro One requested that a 2007 revenue deficiency deferral account be established beginning January 1, 2007 to record the revenue deficiency between the approved revenue for 2007 and the forecast revenues at currently approved transmission rates. Hydro One requested a decision from the Board on this issue by March 31, 2007. The Board issued Procedural Order No. 4 on March 12, 2007 inviting intervenors to make submissions on this request.

On March 30, 2007, the Board issued a Partial Decision and Order approving the establishment of the 2007 revenue deficiency deferral account.

The Settlement Conference was held on March 26, 2007 and on April 3, 2007 the Settlement Proposal was filed with the Board and was the subject of the Settlement Proposal hearing held on April 10, 2007. The Board issued its Settlement Decision on April 18, 2007.

The oral hearing began on April 23, 2007 and concluded on June 13, 2007.

Procedural Order No. 5 was issued on June 26, 2007 regarding submission of cost claims by eligible intervenors.

PARTICIPANTS AND REPRESENTATIVES

Below is a list of participants and their representatives who were active either at the oral hearing or at another stage of the proceeding. A complete list of intervenors is available at the Board’s offices.

Board Counsel and Staff	Donna Campbell Jennifer Lea Harold Thiessen Nabih Mikhail Chris Cincar Wade Frost Martin Davies
Hydro One Networks Inc.	Don Rogers Joe Toneguzzo
Society of Energy Professionals	Richard Long Sonia Pylyshyn
IESO	David Short
Consumers Council of Canada	Robert Warren Julie Girvan
Ontario Power Generation	Tony Petrella
Association of Major Power Consumers of Ontario	Mark Rodger Wayne Clark
Energy Probe	David MacIntosh Tom Adams
School Energy Coalition	John De Vellis
Vulnerable Energy Consumer's Coalition	Michael Buonaguro Bill Harper
Power Workers Union	Richard Stephenson

WITNESSES

There were 20 witnesses who testified at the oral hearing.

The following Company employees appeared as witnesses at the oral hearing:

Frank Jacob	Manager, Program Integration and Regulatory Filing
Mike Penstone	Director, System Investment
George Carleton	Director, Supply Chain Services, Finance
Andy Stenning	Director, Station Maintenance

Naren Pattani	Manager, Transmission System Development
Nairn McQueen	Vice President, Engineering and Construction Services
Paul Tremblay	Director, Network Operating, Grid Operations
Judy McKellar	Director, Human Resources
Sandy Struthers	Chief Information Officer
Greg Van Dusen	Director, Business Integration
Ian Innis	Director, Corporate Planning and Regulatory Finance
William Paolucci	Assistant Treasurer, Treasury Division
Andy Poray	Director, Regulatory Policy and Support
Stanley But	Manager, Economics and Load Forecasting
Henry Andre	Manager, Regulatory Affairs, Corporate Regulatory Affairs

In addition, the Company called the following witness:

Kathleen McShane	President and Senior Consultant, Foster Associates Inc.

Witnesses called by intervenors:

For AMPCO:

Wayne Clark	Consultant, SanZoe Consulting, Inc.
Darren MacDonald	Director of Energy, Gerdau Ameristeel
Gary Saleba	President and CEO, EES Consulting

For VECC/CCC:

Dr. Laurence D. Booth	CIT Chair, Structured Finance, Rotman School of Management, University of Toronto

In addition, evidence was filed by York University professors Dr. Fred Lazar and Dr. Eli Prisman on behalf of Board staff. Drs. Lazar and Prisman did not appear as witnesses in the oral hearing.

APPENDIX 2

HYDRO ONE NETWORK INC.
2007 AND 2008 ELECTRICITY TRANSMISSION RATES

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0501

SETTLEMENT PROPOSAL

August 16, 2007

Hydro One Networks Inc.
Test Year 2007/2008 Transmission Rates
EB-2006-0501

SETTLEMENT PROPOSAL

Preamble:

This settlement proposal is filed with the Ontario Energy Board ("the Board") in connection with the application by Hydro One Networks for an Order or Orders approving the revenue requirement and customer rates for the transmission of electricity to be implemented in 2007.

Further to the Board's Procedural Order No. 2 dated December 20, 2006, a settlement conference was held on March 26 and 27, 2007 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* ("Rules") and the Board's Settlement Conference Guidelines ("Guidelines").

Hydro One Networks and the following intervenors ("the parties") participated in the settlement conference:

Association of Major Power Consumers in Ontario ("AMPCO")
Consumers Council of Canada ("CCC")
Electrical Distributors Association (EDA)
Energy Probe Research Foundation ("Energy Probe")
Independent Electricity System Operator ("IESO")
Ontario Power Generation ("OPG")
Power Workers' Union ("PWU")
School Energy Coalition ("SEC")
Society of Energy Professionals (SEP)
Vulnerable Energy Consumers Coalition ("VECC")

Ontario Energy Board staff also participated in the settlement conference but are not party to this settlement proposal.

Outlined below are the positions of the parties following the settlement conference. The settlement proposal follows the format of the Approved Issues List for ease of reference. The issues are characterized as follows:

Settled: If the settlement proposal is accepted by the Board, the parties will not adduce any oral evidence during the hearing as the applicant and the intervenors who take any position on the issue agree to the proposed settlement.

Partially Settled: If the settlement proposal is accepted by the Board, the parties will only adduce evidence on portions of the issues as the applicant and the intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue.

Not Settled: The applicant and the intervenors who take a position on the issue will adduce evidence at the hearing on the issue as the parties were unable to reach agreement.

For ease of reference, the following outlines the status of the issues as outlined in the settlement proposal:

Settled: Issue completely resolved. Parties will not adduce evidence at the hearing.	**Partially Settled:** Issue partially resolved. Parties will adduce evidence at hearing on certain portions of the issue.	**Not Settled:** Issue not resolved. Evidence to be adduced on entirety of issue.
# issues settled: 24	# issues partially settled: 2	# issues not settled: 14

The positions taken by the various parties on each of the settled or partially settled issues are identified throughout the settlement proposal.

The settlement proposal provides a brief description of each of the settled and partially settled issues, together with references to the evidence filed to date. The parties to the settlement proposal agree that the evidence filed to date in respect of each settled or partially settled issue supports the proposed settlement. In addition, the parties agree that the evidence filed in support of each settled or partially settled issue contains sufficient detail, rationale and quality information to allow the Board to make findings in keeping with the settlement or partial settlement reached.

The settlement of issues 8.1 and 8.2 are proposed as a package. The balance of the issues in the settlement proposal are not proposed to the Board as a package settlement. As such, the parties acknowledge that the Board may accept settlement on any individual issue, or combination of them.

1. ADMINISTRATION (Exhibit A)

1.1 Are the Affiliate Service Agreements still cost effective and efficient in delivering services? Have any changes occurred in these arrangements since the 2006 distribution rates proceeding (RP-2005-0020/EB-2005-0378)? (A1/T8/S2)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

A-8-2 Affiliate Service Agreements

J-1-1, J-1-2, J-1-3, J-5-1, J-5-2, J-5-3, J-5-4, J-5-5, J-5-6, J-9-36, J-9-37, J-9-38

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

1.2 Has Hydro One addressed all relevant Board directions from previous proceedings? (A/T17/S1)

Settled. The parties accept the Applicant's position on this issue, as it was agreed that the following matters, for which agreement could not be reached, would be addressed in the context of other issues. The particulars are outlined below.

a) Intervenors are concerned about Hydro One's interpretation of the Board's RP-2005-0501 Decision, which established an Earnings Sharing Mechanism, including the appropriateness of prior year adjustments being made to the 2006 Earnings/Sharing calculation.

The parties agreed this concern would be dealt with as part of the Board's consideration of issue 9.1.

b) Intervenors are concerned about the accuracy of the Net Income amount proposed by Hydro One for the Transmission Earning/Sharing mechanism.

The parties agreed this concern would be dealt with as part of the Board's consideration of issue 9.1.

c) Is Hydro One's proposal to apply the Earnings/Sharing amount as contributed capital appropriate?

The parties agreed this concern would be dealt with as part of the Board's consideration of issue 9.1.

d) Intervenors raised a concern relating to the justification for the Niagara Reinforcement Project

The parties agreed this concern would be dealt with as part of the Board's consideration of issue 3.4. However, the parties were unable to reach agreement on intervenors' concerns relating to the economic justification of the Niagara Reinforcement Project.

e.) Intervenors, except the SEP, raised a concern regarding whether the Company has complied with the following directives, relating to compensation issues, given by the Board in its Decision with Reasons dated April 12, 2006 in EB-2005-0378: "the Board expects Hydro One to identify what steps the company has taken or will take to reduce labour rates." [para. 3.4.4]; and, "The Board expects Hydro One to file appropriate evidence in the next main rates case to establish that none of the incentive compensation should be charged to the shareholder." [para. 3.4.7]

The parties, except the SEP, agreed this concern would be dealt with as part of the Board's consideration of issue 2.2.

Evidence:

Exhibit A-17-1, Table 1 (entitled Board Directives from Proceeding RP-1998-0001) identifies the reference exhibit which contains Hydro Ones response to the related directives.

Supporting Parties: AMPCO, CCC, Energy Probe. PWU, SEC, SEP (with the exception that the SEP requested to be excluded from comments in 1.2e), VECC

Parties taking no position: EDA, IESO, OPG,

1.3 <u>Is the proposal to establish a revenue requirement beyond the 2007 and 2008 test years without a separate cost of service approval appropriate?</u>

Not settled. The parties were unable to reach agreement on this issue.

1.4 <u>Is the proposed methodology to establish the future revenue requirement beyond 2007 and 2008 appropriate?</u>

Not settled. The parties were unable to reach agreement on this issue.

1.5 Is the proposal to include capital spending as incurred in Rate Base for 2009-2010 appropriate? (A1/T13/S1)

Not settled. The parties were unable to resolve this issue.

1.6 Are Hydro One's Economic and Business Planning Assumptions for 2007 and 2008 appropriate?

Settled. Intervenors had no concerns with respect to Hydro One's economic and business planning assumptions for 2007 and 2008, except for the assumed interest rates regarding cost of capital. The parties agreed that business and economic planning assumptions utilized by Hydro One for 2007 and 2008 are appropriate.

The parties agreed that concerns regarding Hydro One's interest rates assumptions as they affect cost of capital would be addressed under issue 4.2.

Evidence:

A-9-1 Hydro One Transmission Financial Statements for the Year Ended 2005

A-10-1 Hydro One Inc. – Historic Year Annual Reports

A-10-2 Hydro One Inc. – Budget Year Quarterly Reports

A-14-1 Planning Process

A-14-2 Economic Indicators

A-14-4 Project and Program Approval and Control

J-1-15, J-1-16, J-1-17, J-5-26, J-10-1, J-10-2, J-10-3, J-10-4

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, PWU, SEC, SEP, VECC

Parties taking no position: EDA, OPG

2. COST OF SERVICE (Exhibit C)

2.1 Are the overall levels of the 2007 and 2008 Operation, Maintenance and Administration Budgets appropriate? (C1/T1/S1)

Not settled. The parties were unable to reach agreement on this issue.

2.2 Is the 2007 and 2008 budget for Human Resources related costs (wages, salaries, benefits, incentive payments and pension costs) including employee levels, appropriate? (C1/T3/S1&2)

Not settled. The parties were unable to reach agreement on this issue.

2.3 Is the proposed level of corporate O&M costs allocated to the transmission business for 2007 and 2008 appropriate and in line with the O&M cost allocation approved by the Board in Hydro One's 2006 distribution proceeding (RP-2005-0020/EB-2005-0378)? (C1/T5/S1&2)

Settled. The parties accept the Applicant's position on this issue.

The methodology for allocation of costs, for purposes of setting 2007 and 2008 rates, has been accepted, subject to impacts of Hydro One's Human Resource related costs which is an unsettled issue (Issue #2.2).

Evidence:

C1-5-1 Common Corporate Cost Allocation and Cost Allocation Methodology

J-1-29, J-1-42, J-1-43, J-1-44, J-1-45, J-1-46, J-1-47, J-1-48, J-1-49, J-1-99, J-5-65, J-5-66, J-5-67, J-5-68, J-5-69, J-9-36, J-9-37, J-10-8

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

2.4 Is Hydro One's depreciation expense appropriate for 2007 and 2008 and in line with the depreciation methodology approved by the Board in Hydro One's 2006 distribution application (RP-2005-0020/EB-2005-0378)? (C1/T6/S1&2)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

C1-6-1 Depreciation and Amortization Expenses

C1-6-2 Depreciation Rate Review

C2-5-1 Depreciation and Amortization Expenses

J-1-50, J-5-70, J-9-54

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

2.5 Is Hydro One's proposed transmission overhead capitalization rate appropriate? (C1/T5/S2)

Settled. The parties accept the Applicant's proposed overhead capitalization rate.

Evidence:

C1-5-2 Overhead Capitalization Rate

J-1-51, J-1-52, J-1-53 (overlap with issue 3.3), J-1-54, J-1-77ii, J-5-71

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

2.6 Are the amounts proposed to be included in 2007 and 2008 revenue requirements for capital and property taxes appropriate? (C2/T4/S1)

Settled. The parties accept the Applicant's position on this issue.

Note the Capital Tax amount for 2006 is currently under review and will be revised subject to finalization of results and audit review. Audited Transmission Financial statements will be filed when available during the hearing. Hydro One commits to filing an update of 2006 capital taxes using the audited 2006 financial statements.

Evidence:

C2-4-1 Capital Taxes

C1-2-6 Property Taxes

J-1-55, J-1-56, J-1-57, J-1-58, J-5-72, J-7-23

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

2.7 Is the amount proposed to be included in 2007 and 2008 revenue requirements for income taxes, including the methodology, appropriate? (C1/T7/S1)

Settled. The parties accept the Applicant's position on this issue.

Additional information was provided during the Settlement process. It was agreed that the 2007 Federal and Provincial Budgets will not have a material impact on HONI's revenue requirement in 2007. Any impacts arising from those budgets will be captured in the proposed Tax Rate Changes Variance Account.

Evidence:

C1-7-1 Payments in Lieu of Corporate Income Taxes

C2-6-1 Calculation of Utility Income Taxes

J-1-59, J-1-60, J-1-62

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

3. RATE BASE (Exhibit D)

3.1 Are the amounts proposed for the 2007 and 2008 Rate Base appropriate? (D1/T1/S1)

Partially Settled. The parties have agreed that the proposed amounts for the 2007 and 2008 rate base are appropriate, except for the amounts proposed for capital expenditures in 2007 and 2008 to be dealt with under issue 3.2. Rate base will be modified to reflect any subsequent changes to capital expenditures in 2007 and 2008 resulting from the resolution of issue 3.2.

During the Settlement Conference, additional information was provided that deals with $7.3M of OEFC owned assets in Hydro One's rate base[1].

Evidence:

D1-1-1 Rate Base

D1-1-3 Level and Appropriateness of Transmission Assets

D2-1-1 Statement of Utility Rate Base

J-1-58, J-1-63, J-1-64, J-1-65, J-5-73

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

3.2 Are the amounts proposed for Capital Expenditures in 2007 and 2008 appropriate? (D1/T3/S1&3)

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[1] Hydro One made payment for these assets as part of the settlement for the acquisition of assets from Ontario Hydro.

Due to jurisdictional issues and due to the fact that underlying land permits did not allow assignment without federal governmental consent, assets owned by Ontario Hydro on Reserves did not pass to HONI under the transfer orders. Instead, these were held by OEFC, as the continuation of Ontario Hydro, in trust for HONI. Pursuant to an Indemnity and Trust Agreement between OEFC and HONI, it is clear that OFEC is merely holding these assets in trust for HONI as the beneficial owner. HONI has all of the operational responsibility for the assets and has indemnified OEFC completely and comprehensively from any and all liabilities and responsibilities arising from the assets, or the underlying permits.

Not settled. The parties were unable to reach agreement on this issue.

3.3 Is Hydro One's corporate asset allocation for the transmission business in line with the common capital and common asset allocation approved by the Board in Hydro One's 2006 distribution application (RP-2005-0020/EB-2005-0378)? (C1/T5/S3) (D1/T3/S5)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

C1-5-3 Common Asset Allocation

J-1-53 (overlap with issue 2.5), J-1-99, J-5-91

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

3.4 Is the proposed inclusion of "Supply Mix" Capital Project expenditures in 2007 and 2008 Rate Base as they are incurred, appropriate? (D1/T1/S4)

Not settled. The parties were unable to reach agreement on this issue.

In addition, the parties were unable to reach agreement on intervenors' concerns relating to the economic justification of the Niagara Reinforcement Project (from issue 1.2).

3.5 Is the submitted Lead Lag study appropriate for the development of the Working Capital component of the Rate Base? (D1/T1/S5)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

D1-1-5 Working Capital and Lead/Lag Study

J-1-63, J-1-104, J-5-94, J-7-28

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

3.6 Does the Asset Condition Assessment adequately address the current condition of the transmission system assets and the determination of capital needs of the system in the future? (D1/T2/S1)

Settled. The parties accept the adequacy of the Applicant's Asset Condition Assessment but without prejudice to their position on capital spending levels.

Evidence:

D1-2-1 Asset Condition Study

J-1-105, J-1-106, J-3-4, J-5-29, J-5-31, J-5-34, J-5-77, J-5-95, J-5-96, J-5-97, J-5-98, J-6-2

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

3.7 Is the method that Hydro One has used to calculate AFUDC appropriate? (D1/T4/S1)

Settled. Hydro One has agreed that the AFUDC will be calculated using the rate approved by the Board for distribution companies, to be effective January 1, 2007.

Evidence:

D1-4-1 Allowance for Funds Used During Construction

J-1-68, J-1-69

Supporting Parties: AMPCO, CCC, Energy Probe, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG, PWU ("not opposed")

4. COST OF CAPITAL/CAPITAL STRUCTURE (Exhibit B)

4.1 What is the appropriate Capital Structure for Hydro One Networks' transmission business for the 2007 and 2008 test years? (B1/T1/S1) (B1/T3/S2)

Not settled. The parties were unable to reach agreement on this issue.

4.2 What is the appropriate Return on Equity (ROE) for Hydro One Networks' transmission business for the 2007 and 2008 test years? (B1/T1/S1) (B1/T3/S2)

Not settled. The parties were not able to reach agreement on this issue.

4.3 Are Hydro One's proposed costs for its debt and preference share components of its capital structure appropriate? (B1/T2/S1)

Not settled. The parties were not able to reach agreement on this issue.

4.4 Should the Capital Structure, Capital Costs and Rate of Return on Equity vary between Hydro One's distribution and transmission businesses? (B1/T3/S1)

Not settled. The parties were unable to reach agreement on this issue.

5. REVENUE REQUIREMENT (Exhibit E)

5.1 Is the proposed amount for 2007 and 2008 External Revenues, including the methodology used to cost and price these services, appropriate? (E3/T1/S1)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

E3-1-1 External Revenues

J-5-104, J-5-105, J-7-41, J-7-42, J-7-43

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

6. COST ALLOCATION (Exhibit G)

6.1 Are Hydro One's proposed cost pools appropriate and have the costs assigned to these pools been allocated appropriately? (G1/T1-6)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

G1-1-1 Cost Allocation and Charge Determinants

G1-2-1 Description of Cost Allocation Methodology

G1-3-1 Network and Line Connection Pools

G1-4-1 Transformation Connection Pool

G1-5-1 Wholesale Meter Pool

G1-6-1 Cost Data for Low Voltage Switchgear Compensation

G2-5-1 Detailed Revenue Requirement by Rate Pool

H1-5-3 Disposition of Export Transmission Service Revenues

J-1-4, J-1-136, J-1-138, J-5-106, J-5-107, J-5-108, J-5-109, J-5-110, J-5-111, J-5-112, J-5-113, J-5-114, J-5-115, J-5-123, J-8-4

AMPCO Evidence, Testimony of Gary S. Saleba, Pg. 11 Line 16-18

J-13-1 (Pg.2 under the heading "Hydro One Cost Allocation")

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, OPG, PWU, SEC, SEP, VECC

Parties taking no position: EDA

6.2 Is the proposed cost allocation treatment of "dual function" lines appropriate? (G2/T2/S1)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

G1-2-1 Description of Cost Allocation Methodology

G1-3-1 Network and Line Connection Pools

G2-2-1 Allocation Factors for Dual Function Lines

G2-4-1 Asset Value by Functional Category

G2-4-2 Total Depreciation by Functional Category

G2-4-3 Return on Capital and Income Taxes by Functional Category

G2-4-4 OM&A Costs by Functional Category

J-5-107, J-5-108, J-5-109, J-5-111, J-5-114, J-5-115,

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

6.3 Is it appropriate to create a Wholesale Meter pool and was the establishment of this pool done appropriately? (G1/T5/S1)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

G1-2-1 Description of Cost Allocation Methodology

G1-5-1 Wholesale Meter Pool

G2-5-1 Detailed Revenue Requirement by Rate Pool

J-5-107, J-5-111

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, OPG, PWU, SEC, SEP, VECC

Parties taking no position: EDA

6.4 Should the customers directly connected to Network Stations that do not pay Line Connection Charges pay them and if so, what mechanism should be used? (G1/T3/S1)

Settled. The parties agreed to resolve this issue and agree that the status quo is appropriate for this case. Hydro One has undertaken to conduct an internal study on connection facilities terminating in Network Stations and associated connection charges to be submitted as part of the next transmission rate application.

Evidence:

G1-3-1 Network and Line Connection Pools

J-1-137

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

6.5 <u>To what cost pools should "Local Loops" be allocated? (G1/T3/S1)</u>

Settled. The parties accept the Applicant's position on this issue.

Evidence:

G1-3-1 Network and Line Connection Pools

J-1-138, J-5-115

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

7. RATE DESIGN and CHARGE DETERMINANTS (Exhibit H)

7.1 <u>Is the load forecast and methodology appropriate and have the impact of Conservation and Demand Management initiatives been suitably reflected? (A1/T14/S2&3) (H1/T2/S1)</u>

Not settled. The parties were unable to reach agreement on this issue.

7.2 <u>Have the proposed charge determinants been forecast appropriately for each of the transmission revenue pools? (G1/T1/S1) (H1/T3/S1)</u>

Settled. The parties accept the Applicant's position on this issue.

Evidence:

G1-1-1 Cost Allocation and Charge Determinants

H1-3-1 Charge Determinants

H1-4-1 Rates for Wholesale Meter Service

Supporting Parties: AMPCO, CCC, Energy Probe, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG, PWU ("not opposed")

7.3 <u>Is the proposal to continue with the status quo charge determinants for Network and Connection service appropriate? (H1/T3/S1)</u>

Partially settled. The parties were able to agree that the current charge determinants for Connection service are appropriate. The parties were unable to reach agreement on whether the current charge determinants for Network service are appropriate.

Evidence:

H1-3-1 Charge Determinants

J-5-122

Supporting Parties: AMPCO, CCC, EDA; Energy Probe, IESO, PWU, SEC, SEP, VECC

Parties taking no position: OPG

7.4 <u>Is it appropriate to continue the Export Transmission Service Tariff and should this tariff be changed? (H1/T5/S1, 2 & 3)</u>

Settled. The parties were able to reach agreement on this issue.

After identifying alternatives as directed by the Board, Hydro One assumed that the status quo of $1.00/MWh would continue, for the purposes of its application.

The parties have agreed that the status quo ETS tariff of $1/MWh should be maintained for the time being, but that the IESO should now be identified as the entity responsible to pursue and negotiate, with neighbouring jurisdictions, acceptable reciprocal arrangements with the intention to eliminate the ETS tariff, and study the appropriate ETS tariff, including those options identified in H1/T5/S1. The IESO will seek input from market participants and interested intervenors in this proceeding and keep the parties informed of the progress of negotiations and the study. It is agreed that the IESO will make its report available to the Board upon completion which will be no later than June 1, 2009 with the results of reciprocal arrangement negotiations and the study including recommendations for an appropriate ETS tariff. Hydro One Networks Inc. remains responsible for seeking changes to its approved transmission revenues and rates and will do so as part of the 2010 transmission rate-resetting process period, following the publishing of the study.

Evidence:

H1-5-1 Rates for Export Transmission Service

H1-5-2 Review of Export Tariffs in Other Jurisdictions

H1-5-3 Disposition of Export Transmission Service Revenues

J-1-144, J-1-145, J-1-146, J-1-147, J-1-148, J-5-106, J-5-125, J-5-126

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, OPG, SEC, SEP, VECC

Parties taking no position: EDA, PWU ("not opposed")

8. OTHER ISSUES

8.1 <u>Is the proposal for the establishment and methodology of Hydro One's 2007 and 2008 Deferral and Variance Accounts appropriate? (F1/T3/S1)</u>

Settled. The parties have agreed, as part of a package, to resolve this issue together with issue 8.2 as follows:

i) The amount of the Deferred Export Transmission Service Credit is $54.5M (Update).

ii) The Ontario Energy Board Cost Account will not be altered to reflect load growth.

iii) The Market Ready Cost Account will be reduced by 10%, even though it has already been reduced to reflect the OEB Distribution decision. This value after a 10% reduction is $16.7M as at April 30, 2007.

Note: The 10% reduction to principal was calculated effective December 2004 (consistent with the date of adjustments arising from the Distribution market ready decision). This amount is then interest improved to arrive at the value of $16.7M as at April 30, 2007.

iv) Interest on all variance accounts will be that approved by the Board for distribution companies, to be effective January 1, 2007.

v) All variance accounts will be cleared over four years in order to facilitate rate smoothing.

In addition, as it relates to new accounts, the parties agree that the following requested new variance accounts should be approved:

1. OEB Cost Assessment Differential

2. Tax Rate Changes

3. Transmission System Code Changes

4. Pension Cost Differential

The parties further agree to await the Board’s decision on the 2007 Revenue Deficiency Deferral Account presently under reserve.

As the recent federal and provincial budgets have not been formally passed into law, any tax impacts of those budgets will be recorded in the new Tax Rate Changes Account, once formalized.

Evidence:

F1-1-1 Regulatory Assets

F1-1-2 Variances Resulting From Board Decisions

F1-2-1 Planned Disposition of Regulatory Assets

F1-3-1 Variance Account Requested

F2-1-1 Regulatory Assets

F2-1-2 Schedule of Annual Recoveries

J-1-149, J-1-150, J-1-151, J-1-152, J-1-153, J-1-154, J-1-155, J-5-19, J-5-127, J-5-128, J-5-129

Supporting Parties: AMPCO, CCC, Energy Probe, IESO (v), SEC, SEP, VECC

Parties taking no position: EDA, IESO [(i) to (iv) and new accounts], OPG, PWU ("not opposed")

8.2 Is the proposal for the amounts and disposition of Hydro One's existing Deferral and Variance Accounts (Regulatory Assets) appropriate? (F1/T1/S1)

Settled. The parties have resolved this issue as a package with issue 8.1, outlined above.

Evidence: see issue 8.1 above.

Supporting Parties: AMPCO, CCC, Energy Probe, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG, PWU ("not opposed")

8.3 Has Hydro One delivered an adequate level of service and other performance compared with other jurisdictions and other relevant performance standards? (A1/T15/S1, 2&3)

Settled. The parties accept the Applicant's position on this issue. The parties have agreed that the issue related to customer delivery point performance standards would be addressed as part of proceeding RP-1999-0057/EB-2002-0424.

Evidence:

A-15-1 Transmission Business Performance

A-15-2 Transmission Benchmarking

A-15-3 Customer Delivery Point Performance Standards

J-1-33, J-1-35, J-1-36, J-1-38, J-1-156, J-1-157, J-1-158, J-1-159, J-1-160, J-1-161, J-1-162, J-1-163, J-1-164, J-1-166, J-2-6, J-3-1, J-3-4, J-3-5, J-5-130, J-5-131, J-5-132, J-5-133, J-5-134, J-5-135, J-5-136, J-5-137, J-6-3, J-6-4, J-7-7, J-8-5

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, OPG, PWU, SEC, SEP, VECC

Parties taking no position: EDA

8.4 Has Hydro One demonstrated the need to reinforce the existing 115kV connection lines between Leaside TS and Birch Junction TS in the city of Toronto project? (D2/T2/S3)

Settled. The parties were able to reach agreement on this issue. The parties agreed that the applicant has demonstrated the need to relieve loading on the existing 115kV connection lines between and Leaside and Birch Junction TSs.

The Applicant has agreed that the issues regarding options, alternatives and costing of the mitigating alternatives will be deferred from this rate application to be dealt with in a separate section 92 application to the Board.

Evidence:

D2-2-3 Justification for Programs or Projects in excess of $3 Million (#D18 Leaside x Birch Junction Transmission Reinforcement)

J-1-167, J-5-138

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, PWU, SEC, SEP, VECC

Parties taking no position: EDA, OPG

9. RATE IMPLEMENTATION

9.1 <u>How should the Board deal with any revenue implications regarding the Hydro One Transmission earnings/sharing mechanism (EB-2005-0501) established by the Board?</u>

Not settled. The parties were unable to reach agreement on this issue.

Also, the parties agreed that the following concerns would be dealt with as part of the Board's consideration of issue 9.1 rather than issue 1.2.

a) Intervenors are concerned about Hydro One's interpretation of the Board's RP-2005-0501 Decision, which established an Earnings Sharing Mechanism, including the appropriateness of prior year adjustments being made to the 2006 Earnings/Sharing calculation.

b) Intervenors are concerned about the accuracy of the Net Income amount proposed by Hydro One for the Transmission Earning/Sharing mechanism.

c) Is Hydro One's proposal to apply the Earnings/Sharing amount as contributed capital appropriate?

9.2 <u>Are the bill impacts as a result of this application for various customer groups reasonable? (A1/T2/S1)</u>

Not settled. The parties agreed that this issue could not be resolved at this time.

APPENDIX 3

HYDRO ONE NETWORK INC.
2007 AND 2008 ELECTRICITY TRANSMISSION RATES

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0501

SETTLEMENT DECISION

August 16, 2007

EB-2006-0501

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the transmission of electricity commencing January 1, 2007.

SETTLEMENT PROPOSAL DECISION

Hydro One Networks Inc. ("Hydro One" or the "Company") filed an Application, dated September 12, 2006, with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act 1998, S.O. 1998*, c.15, Schedule B. The Board assigned file number EB-2006-0501 to the Application and issued a Notice of Application dated October 17, 2006.

On April 3, 2007, Hydro One Networks Inc. filed a Settlement Proposal that was developed and agreed to by Hydro One and ten intervenors in this proceeding. The Settlement Proposal indicates that the parties reached full settlement on 24 issues and partial settlements on two issues. There was no settlement on fourteen issues.

Hydro One presented the proposal to the Board at a settlement hearing on April 10, 2007 (together with some additional clarifying statements on settled Issues 1.2 and 6.5). Board staff made submissions on two settled issues – 8.1 and 8.2, which relate to deferral and variance accounts – and recommended that those issues be removed from the proposal.

On April 10, 2007, the Board accepted the Settlement Proposal[1] except for issues 7.4, 8.1, 8.2 and 8.4. The Board's decision on these issues is below.

Issue 7.4 – Export Transmission Service Tariff

Issue: "Is it appropriate to continue the Export Transmission Service Tariff and should this tariff be changed?"

The settlement proposal stated that the status quo of $1.00/MWh would continue. It also went on to describe agreement on the role that the IESO would take in negotiating acceptable reciprocal arrangements with neighbouring jurisdictions, studying the appropriate ETS tariff and making its report available to the Board. At the settlement hearing, the Board asked the parties to consider whether or not the issue could be settled by simply agreeing to the status quo and removing the additional discussion in the proposal on future actions by the Independent Electricity System Operator (IESO)[2].

After consulting with the settling parties, on April 11, 2007, Hydro One filed with the Board modified settlement language for this issue. Although the settlement continues to refer to possible future action by the IESO, the language makes clear that the Board is not approving the future actions of the IESO and that any change to the ETS charge must be made through a Board rates process. The settlement language is now in a form satisfactory to the Board. The Board accepts the modified settlement proposal for this issue.

Issue 8.4 – Leaside TS to Birch Junction TS Reinforcement

Issue: "Has Hydro One demonstrated the need to reinforce the existing 115kV connection lines between Leaside TS and Birch Junction TS in the City of Toronto project?"

[1] Transcript, April 10, 2007, page 91.
[2] Transcript, April 10, 2007, page 36.

The settlement proposal agreed that the need to relieve loading on the existing 115kV connection lines between Leaside TS and Birch Junction TS had been demonstrated and was accepted. The proposal also stated agreement that the issues regarding options, alternatives and costing of the mitigating alternatives will be deferred from this rate application to be dealt with in a separate section 92 application to the Board. In the oral hearing of the settlement proposal, the Board indicated that it could not accept the proposed settlement on this issue because it would mean the need for this project would not be examined on the record.[3] The Board asked Hydro One to consider two options for addressing the need for this project: moving the issue from this rates case to the Section 92 leave to construct proceeding for the project, or by having a Hydro One witness panel address the need issue as part of this rate hearing.

On April 11, 2007, Hydro One informed the Board that it will present evidence on the need to relieve loading on the existing 115kV connection lines between Leaside TS and Birch Junction TS at this hearing. The Board accepts the remainder of the settlement on this issue, being the deferral of issues on options, alternative and costing of mitigating alternatives to a section 92 application.

Issues 8.1 and 8.2 – Deferral and Variance Accounts

Issue 8.1, "Is the proposal for the establishment and methodology of Hydro One's 2007 and 2008 Deferral and Variance Accounts appropriate?"
Issue 8.2, "Is the proposal for the amounts and disposition of Hydro One's existing Deferral and Variance Accounts (Regulatory Assets) appropriate?"

At the settlement hearing, Board staff made submissions on general policy issues with respect to deferral and variance accounts being established through settlement agreements. Staff also expressed some particular concerns on the specific accounts referred to in the proposed settlement of Issue 8.1. The Board

[3] Transcript, April 10, 2007, page 80.

indicated it would consider the issues further in light of the submissions by Board staff.

Policy Issues

Board staff submitted that there are "policy dimensions to creating the variance and deferral accounts that Staff believes should be addressed on a more comprehensive basis than is permitted by the settlement process."[4] Staff noted that its concerns extended to the disposition of account balances as well as the creation of accounts. Staff advocated that Issues 8.1 and 8.2 not be accepted by the Board as settled issues; rather, the issues should be explored in the hearing. In addition, Board staff submitted that "for policy reasons perhaps it is now the time for the Board to consider whether or not the creation of such accounts should in fact be part of a settlement proposal."[5]

Hydro One, VECC and CCC indicated that in other rates cases the Board has accepted many settlement agreements that have dealt with deferral and variance accounts. Hydro One submitted that if the Board wishes to establish a policy that these accounts should not be considered in settlement agreements, it should seek input from larger group than just the parties in this particular rates case.

Specific Deferral and Variance Accounts

Three existing deferral accounts are covered by Issues 8.1 and 8.2. Board staff submitted that the Board should not accept the settlement because the Board should explicitly address whether the accounts were authorized, the prudence of the expenditures included in the accounts, and the disposition of the accounts.[6] Staff observed that Hydro One did not seek, and was not given, permission by

[4] Transcript, April 10, 2007, pp. 57 and 58.
[5] Transcript, April 10, 2007, page 48.
[6] Transcript, April 10, 2007, page 63.

the Board to establish one of the accounts, the Ontario Energy Board Cost Account.

None of the parties to the settlement proposal object to Hydro One establishing the following four new variance accounts: OEB Cost Assessment Differential; Tax Rate Changes; Transmission System Code Changes; and, Pension Cost Differential. Board staff submitted that the Board should reject the settlement on these accounts and, instead, should consider whether the accounts meet criteria used in the past by the Board when granting deferral and variance accounts for electricity distributors.

The settlement proposal for Issue 8.1 refers to a possible fifth new account and states: “The parties further agree to await the Board’s decision on the 2007 Revenue Deficiency Deferral account presently under reserve.” The Board understands that this language was included in error and is unnecessary given that the Board has already authorized that account in Procedural Order No. 4 issued on March 12, 2007.

Board Findings

With respect to the general policy issues raised by Board staff, the Board does not believe that this rates case is the right forum to address those issues. The Board agrees with Hydro One that if this issue is to be addressed the Board should seek input from a wider group, including parties active in the natural gas sector.

Deferral and variance accounts are used extensively by the OEB in both natural gas and electricity rates cases The OEB may want to review its regulatory agenda to determine if it should initiate a public policy process to examine the issues associated with the use of these accounts.

The Board will accept the settlement proposal for existing deferral accounts, including the four-year period over which the balances will be cleared, except that the Board will not accept the settlement in respect of the Ontario Energy Board Cost Account. As Board staff noted, Hydro One never applied to the Board to establish that account. If Hydro One continues to believe that the balance in that account should be recovered through future rates, then the Board expects Hydro One to provide evidence in this hearing as to why it would be appropriate for the company to recover such costs given that it did not apply to the Board for a deferral account at the time the costs were being incurred.

The Board also accepts the settlement proposal to establish four new variance accounts. Hydro One and the other parties to the settlement should be aware that the Board is providing no assurance that any amounts in those accounts in the future will be included in rates, nor does the approval of the establishment of these accounts indicate any acceptance by the Board of the types of expenditures being recorded in the accounts.

DATED at Toronto, April 18, 2007.

ONTARIO ENERGY BOARD

Signed on Behalf of the Panel

Original signed by

Pamela Nowina
Vice Chair, Presiding Member

APPENDIX 4

HYDRO ONE NETWORK INC.
2007 AND 2008 ELECTRICITY TRANSMISSION RATES

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0501

PARTIAL DECISION AND ORDER
Issued
March 30, 2007

August 16, 2007

Ontario Energy Board

Commission de l'Énergie de l'Ontario

EB-2006-0501

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the transmission of electricity commencing January 1, 2007.

PARTIAL DECISION AND ORDER

Hydro One Networks Inc. ("Hydro One" or the "Company") filed an Application, dated September 12, 2006, with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act 1998, S.O. 1998*, c.15, Schedule B. The Board assigned file number EB-2006-0501 to the Application and issued a Notice of Application dated October 17, 2006.

By letter dated February 14, 2007 and in the February 23, 2007 update to its application, Hydro One requested that a 2007 revenue deficiency deferral account be established beginning January 1, 2007 to record the revenue deficiency between the approved revenue for 2007 and forecast revenues at currently approved transmission rates. Hydro One requested a decision from the Board on this issue by March 31, 2007.

On March 12, 2007 the Board issued Procedural Order #4 requesting that Hydro One make further submissions addressing the following issues:

- The need for the revenue deficiency deferral account;
- Why the issue of the account must be dealt with on an expedited basis;

- What will be booked into the account, and the accounting entries that are proposed to be made;
- The date upon which Hydro One proposes to start booking entries into the account; and
- What, if any, consequences follow if the account is not established at all, or is not established prior to March 31, 2007 as requested.

The procedural order also invited intervenors to respond to Hydro One's submissions and then provided for Hydro One's subsequent reply submissions.

Hydro One Submissions:

Hydro One, in its March 13, 2007 submissions, stated that the EB-2005-0501 transmission earnings sharing mechanism (ESM) was intended to end once new transmission rates were implemented. The establishment of the 2007 revenue deficiency deferral account (RDDA) beginning January 1, 2007, would replace and end the ESM.

Hydro One claimed that the proposed RDDA was more transparent than the ESM, and would be easier to justify and implement for a portion of a year (as un-audited financial results would be used.) In contrast, the part-year RDDA calculations would be based upon approved data consistent with Hydro One Transmission 2007 rate filing. A rates decision in late 2007 would lead to regulatory lag and uncertainty regarding Hydro One in financial markets. An RDDA was also consistent with the Great Lakes Power Limited (GLPL) deferral account (EB-2005-0241) granted in 2005. A decision by March 31, 2007 was requested due to first quarter financial reporting requirements to external investors.

Under the proposed plan, Hydro One submitted that no amounts would be recorded for the ESM in 2007; however, on a monthly basis, the deficiency between the proposed revenue 2007 requirement (per the Hydro One Transmission rate filing) and revenue calculated using current approved rates (by applying a weather normal monthly load forecast consistent with the 2007 load forecast) would be reflected in the deferral account. Monthly carrying costs would be applied to this entry using the short-term interest rate included in the 2007 revenue requirement. Disposition of the account would be subject to future OEB review and approval. Entries would be booked immediately upon receiving a favourable decision from the OEB reflecting the commencement date of January 1, 2007.

Intervenors' Submissions:

Four intervenors responded to the Hydro One submission. The Vulnerable Energy Consumers Coalition (VECC) and Schools Energy Coalition (SEC) argued against granting the account. The Association of Major Power Consumers (AMPCO) and the Power Workers Union (PWU) were supportive of the request.

VECC argued that approval of this account was retroactive ratemaking and should not be approved by the Board. The GLPL case should not be considered as a precedent in this application as the deferral account granted to GLPL was only one aspect of a comprehensive settlement agreement. In addition, the GLPL account only applied to deficiencies starting on April 1, 2005, not January 1. VECC also argued that if the account was granted, no interest should be collected in the account.

SEC argued that the Board does not have the authority to revisit rates. SEC noted that in the EB-2005-0501 ESM decision, the Board stated that it was reluctant to have existing rates declared interim and if the Board had meant the mechanism to last only until January 1, 2007, it would have said so. SEC indicated that it would be unfair to ratepayers to allow Hydro One to revisit rates during a period where it anticipates a revenue deficiency but not do so during a period of over-earning. SEC also mentioned the fact that the GLPL deferral account was part of a comprehensive settlement agreement. SEC also noted that recent decisions of the Board have refused to implement rates retroactively on basis that the applicant had not demonstrated that the delay in arriving at just and reasonable rates by the beginning of the test year was not due to factors within the applicant's control, citing the January 2, 2007 Erie Thames Powerlines Corporation rate order.

AMPCO did not object to the establishment of the RDDA as this action would reassure investors that regulatory risk is minimal. AMPCO stressed that this approval should not pre-empt the Board's hearing process or be misconstrued as prior approval of Hydro One's revenue requirement. AMPCO submitted that any revenue deficiency calculation should be based on actual, non-weather corrected revenue under current rates and that the RDDA should be based only on continuance of program expenditures at the level Hydro One executed in 2006 and not on the increased levels being requested for 2007.

The PWU also supported the approval of the RDDA citing the need for utilities to have sufficient financial certainty so that they can carry out existing and new transmission work programs. The PWU also agreed with Hydro One that the RDDA was consistent with the GLPL decision and stated that the extended application of ESM for 2007 was inappropriate.

Hydro One Reply Submissions:

In its March 21, 2007 reply, Hydro One indicated that it was not requesting prior approval of its proposed 2007 programs or revenue requirements. Hydro One also submitted that SEC's assertions regarding "retroactive rate increases" are not supported as the OEB is not retroactively setting rates and that it is not revisiting rates for a period during which final rates were in place. Hydro One also noted that the settlement agreement in the GLPL case was the basis for the final order issued November 14, 2005, while the deferral account was granted much earlier on March 22, 2005.

Hydro One also stated that it believes that by requiring the use of audited financial statements for the ESM calculations, the Board intended full year application of the ESM, not part year application.

Hydro One submitted that AMPCO's suggestions that the revenue deficiency be calculated on the basis of non-weather corrected actual 2007 revenue and to use 2006 actual program costs is inconsistent with typical regulatory practice and the GLPL decision. Hydro One also pointed out that the GLPL decision included carrying costs in the approved deferral account.

Findings

It often happens that rate proceedings occur within timeframes that do not coincide with the conventional rate period. This can occur for a variety of reasons. In such situations an issue arises as to when the rates approved by the Board will become effective. Determining the effective date for rates is an important aspect of the Board's jurisdiction, and it can have significance for Applicants and ratepayers.

It is clear that such a situation will arise this year with respect to the revenue requirement for Hydro One. It is likely that the final determination of its revenue requirement for 2007 will not be made until the latter half of 2007.

Deferral accounts, such as the one applied for by Hydro One in this proceeding, are accounting devices intended to allow an entity to capture and record in an identifiable location an aspect of operations, the final quantum and disposition of which is dependent on some future unknown event.

In the case of the deferral account applied for by Hydro One, the unknown future event is the Board's final determination of the 2007 revenue requirement, the effective date governing that revenue requirement, and the terms and conditions imposed by the Board on the disposition, if any, of the amounts recorded in the deferral account.

Parties commenting on Hydro One's request for the Revenue Deficiency Deferral Account have raised issues respecting rate retroactivity, and have attempted to define with great particularity the terms and conditions that should govern the creation of the account, if the Board sees fit to approve its creation.

In the Board's view, the time to make these arguments is in the course of the revenue requirement proceeding per se, and, if necessary, at the time Hydro One seeks to have the amounts recorded in the account disposed of, so as to effect its revenue requirement or the resulting rates derived from it. Parties will be free to make whatever submissions they see fit as to the appropriateness of any disposition option.

At this stage, the Board is simply concerned with ensuring that the account meets the objective of administrative and accounting utility.

Accordingly, the Board approves the creation of a deferral account, effective January 1, 2007, to be referred to as the Revenue Difference Deferral Account. This account will record the sufficiency or deficiency arising from the difference between the 2006 Transmission rates, that is, rates that are currently in force, and the rates that would result from the new revenue requirement as determined by the Board in this proceeding. Parties will note that the Board has made the deferral account symmetrical to account for the possibility that the new revenue requirement as found by the Board may be lower than that which underpinned the 2006 rates.

In its materials, the Applicant referenced the Earnings Sharing Mechanism (ESM), which was instituted by a previous Board panel. In the Board's view, the creation of the deferral account as approved by the Board in this proceeding has the effect of terminating the ESM as of December 31, 2006. That is so because the Revenue Difference Deferral Account now accommodates the tracking of sufficiency as well as deficiency and this fact makes the continuation of the ESM unnecessary. If the new revenue requirement is higher than that underpinning the 2006 rates, the account will represent a credit to the utility to the extent of the difference. On the other hand, if the new revenue requirement is lower than that upon which the 2006 rates are based, the entire amount reflected in the account will be to the credit of ratepayers.

The final balance in the account will reflect a series of decisions made by the Board in its determination of the revenue requirement for 2007.

The Board's approval of the creation of this deferral account should not be construed in any degree as predictive of the quantum of, the terms of or the timing of the disposition, if any, of the contents of this account.

THE BOARD THEREFORE ORDERS THAT:

1. Hydro One shall establish a deferral account in which to record the differences in revenue between 2006 Transmission rates currently in force, and the rates that would result from the new revenue requirement as determined by the Board in this proceeding, beginning January 1, 2007. Hydro One is directed to prepare and submit a draft accounting order to the Board reflecting this order.

DATED at Toronto, March 30, 2007.

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

Maritime Electric Company Limited, for the approval of proposed amendments to its rates, Order UE06-03

COMMISSION DE RÉGLEMENTATION ET D'APPELS DE L'ÎLE

THE ISLAND REGULATORY AND APPEALS COMMISSION

Prince Edward Island
Île-du-Prince-Édouard
CANADA

Docket UE20934
Order UE06-03

IN THE MATTER of an application by Maritime Electric Company, Limited for approval of proposed amendments to its rates.

BEFORE THE COMMISSION

on Tuesday, the 27th day of June, 2006.

Maurice Rodgerson, Chair
Weston Rose, Commissioner
James Carragher, Commissioner
Anne Petley, Commissioner

Order

Compared and Certified a True Copy

(Sgd) *Donald G. Sutherland*

Technical and
Regulatory Services Division

IN THE MATTER of an application by Maritime Electric Company, Limited for approval of proposed amendments to its rates.

Contents

IN THE MATTER of an application by Maritime Electric Company, Limited for approval of proposed amendments to its rates.

Reasons for Order

1. Introduction

[1] This is an application under the ***Electric Power Act***, R.S.P.E.I. 1988, Cap. E-4 (the "*Act*"), by Maritime Electric Company, Limited (the "Applicant", "Maritime Electric" or the "Company") seeking, among other things, an order or orders of the Island Regulatory and Appeals Commission (the "Commission") approving an increase in the Company's basic rates of 3.35% effective July 1, 2006.

[2] The application in this matter was filed on January 31, 2006 and publicly noticed in the Province's daily newspapers and on the Commission's website. In response to the notice, the Commission received a formal intervention from the Prince Edward Island Power Company Limited ("PEI Power") and also received a comment from a member of the public generally opposing the application and a request from a member of the public to make a presentation. The latter request was granted but a presentation was not forthcoming.

[3] The formal intervention filed by PEI Power concerns itself with an application by Maritime Electric for approval of a wind power purchase agreement with the P.E.I. Energy Corporation and the P.E.I. Government. That application is being dealt with separately by the Commission under docket UE21007. PEI Power has also intervened in that case.

[4] Given that PEI Power's interventions in both cases are virtually identical, the Commission will consider the intervention within the context of docket UE21007.

2. The Application

[5] Maritime Electric seeks an Order or Orders of the Commission:

- confirming Maritime Electric's rate bases for the years ended December 31, 2003- 2005 at $188,526,407, $197, 685,922 and $202,501,831 respectively, for establishment of its projected rate bases at $243,638,600 for the year ended December 31, 2006 and at $258,185,100 for the year ended December 31, 2007;
- setting the return on average rate base for the year ending December 31, 2006 of 8.71% to 8.92% and 8.32% to 8.52% for the year ending December 31, 2007; and
- approving an increase in basic rates of 3.35% for July 1, 2006 together with the general Rules and Regulations which relate to those rates for the period July 1, 2006 to December 31, 2007.

3. Discussion & Findings

3.1 Introduction

[6] The application before the Commission involves an assessment of several issues, including the Company forecast of sales and expenditures as well as other matters directly related to the proposed rate increase. In the discussion that follows, the Commission will review these issues and render its findings.

3.2 Sales Forecast

[7] The sales forecast is critical in determining many of the Company's operating expenses particularly those relating to energy purchases. A sales forecast that underestimates growth can, for example, result in a requirement for rates that is higher than necessary and revenue surplus to the needs of the Company.

[8] Prior to deregulation in 1994, the Company's sales forecast was based on an economic model that used historical sales, customer data, population statistics, provincial economic indicators and other related data. This rate application reintroduces these sales modeling techniques; however only short term sales forecasts are provided. Short term energy sales forecasts are based on a two-year average growth rate calculation and the rate of year-to-date growth over the previous year-to-date growth.

[9] Table 1 shows actual and forecast sales levels, by rate class, from 2004 to 2007.

Table 1

Energy Sales 2005 to 2007

	2004 Actual	2005 Actual	2006 Forecast	2007 Forecast
Energy Sales (MWh)				
Residential	410,672	412,122	414,801	418,949
General Service I	341,517	346,149	350,995	356,085
General Service II	5,003	4,850	4,802	4,807
Large Industrial	145,296	145,514	147,279	149,318
Small Industrial	67,412	73,342	77,119	79,626
Street Lighting/Unmetered	6,865	7,273	7,627	7,825
Total Energy Sales	976,765	989,250	1,002,623	1,016,610
Growth Rate (%)				
Residential	3.4	0.4	0.7	1.0
General Service I	0.5	1.4	1.4	1.4
General Service II	0.5	(3.0)	(1.0)	0.1
Large Industrial	(1.8)	.1	1.2	1.4
Small Industrial	10.4	8.8	5.1	3.2
Street Lighting/Unmetered	3.8	5.9	4.9	2.6
Overall Growth Rate	2.0	1.3	1.4	1.4

[10] To assess the reasonableness of the forecast, the Commission has looked at recent actual-to-forecast results, the modeling approach used and the inputs and assumptions used in the model. Past forecast information was not available to the Commission during the period of deregulation. The 1993 general rate case—the last review of the Company's rates prior to deregulation—concluded that there was a positive trend on the part of the Company's forecasting accuracy.

[11] Table 2 compares the most recent forecast-to-actual results.

Table 2

	2004 Forecast	2004 Actual	Actual to Forecast (%)	2005 Forecast	2005 Actual	Actual to Forecast (%)
Energy Sales (MWh)						
Residential	408,184	410,672	0.61%	418,388	412,122	(1.5%)
General Service I	341,820	341,517	(0.09%)	345,922	346,149	0.07%
General Service II	5,027	5,003	(0.48%)	5,135	4,850	(5.55%)
Large Industrial	147,859	145,296	(1.73%)	149,077	145,514	(2.39%)
Small Industrial	68,969	67,412	(2.26%)	72,590	73,342	1.04%
Street Lighting/Unmetered	6,811	6,865	0.79%	6,924	7,273	5.04%
Total Energy Sales	978,670	976,765	(0.19%)	998,036	989,250	(0.88%)

[12] Historically, forecast results have tended to err on the low side of actual results. In the Commission's view, however, the above shows reasonable accuracy in the Company's recent forecasting techniques and provides the Commission with confidence in the forecasts for 2006 and 2007.

[13] Maritime Electric has filed with the Commission its Demand Side Management Plan, Phase 1 for the period 2006-2010 as required by the *Renewable Energy Act*. This *Act* calls for a 5% reduction, by 2010, in the intensity of peak demand as measured in 2004. The impact of this plan is not expected to impact the revenue forecast contained in this application, but will need consideration in the future.

[14] The Commission finds that the projected growth rate of 1.4% in 2006 and 2007 appears reasonable. Although lower than the forecast general growth in the Canadian economy of 3.1% as reported in April by the Bank of Canada, it is more in line with local P.E.I. economic conditions. The Commission accepts the Company's sales forecast of 1,002,623 mWh for 2006.

3.3 Operating Expenditure Forecast

[15] The operating expenses of Maritime Electric are made up of production, transmission, distribution and administrative costs. Production costs—or costs associated with energy supply—represent the largest component of the Company's expenses and overall revenue requirement. These expenses include energy costs to be procured under pre-negotiated energy purchase contracts as well as expenditures associated with the Company's generation facilities in Charlottetown and Borden. Energy purchases from NB Power fall under three contracts: the Point Lepreau Unit Participation Agreement, the Dalhousie Unit Participation Agreement and an Energy Purchase Agreement. Both unit participation agreements extend for the life of the generating stations while the Energy Purchase Agreement is a short-term supply agreement that expires on October 31, 2006.

[16] A summary of energy supply costs is shown below.

Table 3

Energy Cost by Source 2005 to 2007

Source	2005 Actual	2006 Forecast	2007 Forecast
Point Lepreau	$10,590,075	$11,182,800	$11,204,900
Dalhousie	9,092,354	9,717,700	9,878,700
Firm Energy Purchases	24,104,756	5,465,400	10,492,400
System Energy Purchases	15,014,887	36,421,300	37,865,100
Charlottetown Plant	3,011,124	2,662,900	2,781,500
50 MW Combustine Turbine	-	2,177,500	2,158,500
Borden Plant	219,844	245,600	234,800
Wind	2,162,168	4,876,600	13,946,800
Ancillary Services	988,112	1,123,100	1,142,400
Other Purchases	703,778	3,024,400	3,225,900
Amortization Point Lepreau Writedown	560,000	93,400	93,400
Total	$66,447,098	$76,990,700	$93,024,400

[17] The energy cost per source varies by contract and by the fuel source. While some costs are stable and predictable, many are not.

[18] Energy supply constraints with ever increasing demand for energy are causing rising energy costs throughout the marketplace. The rising price of crude oil is a good example of the affects of supply constraints with increasing consumer demand. This is a concern as it may have an impact on new energy supply contracts that will take effect in the fall of 2006.

[19] Transmission expenses relate to those facilities that make up the Company's bulk energy delivery system, from the submarine cables to the inputs in the Company's distribution system. Distribution expenses cover the day to day operating costs of the Company's distribution system and include expenses such as planned maintenance, breakdown and forced outages and equipment failure. General expenses include internal and external costs associated with the overall operation and management of the Company.

[20] A summary of these expenditures, by major category, follows:

Table 4

Maritime Electric Company Limited
Expenses
2005 to 2007

Description of Expenses	Expenditures			% Increase	
	2005 Actual	2006 Forecast	2007 Forecast	2006 Forecast	2007 Forecast
General and Administrative	9,668,500	9,952,500	10,227,100	2.94%	2.76%
Transmission	354,259	363,700	374,100	2.66%	2.86%
Distribution	2,512,277	2,584,900	2,684,300	2.89%	3.85%
Total	12,535,036	12,901,100	13,285,500	2.92%	2.98%

[21] Table 4 shows overall cost increases of 2.92% in 2006 and 2.98% in 2007.

[22] Within the context of published economic forecasts for 2006 and 2007, the Company's forecast appears reasonable. The Commission has, as well, spent considerable time reviewing detailed budget data submitted in response to staff interrogatories and has satisfied itself that forecast expenditure levels are reasonable and prudent.

3.4 Rate of Return

[23] The Commission is guided in determining the allowable return on average common equity rates by the *Electric Power Act* which requires that the return be just and reasonable. Considerable jurisprudence in this area clearly directs that the return must be fair to both the consumer and the shareholder.

[24] Maritime Electric maintains that the rate of return must:

- Earn a return on the value of its property commensurate with that of comparable risk enterprises;
- Maintain its financial integrity; and
- Attract capital on reasonable terms.

[25] Maritime Electric is proposing a return on average common equity in the range of 10.0% to 10.5%. The Company states it will continue to strengthen its capital structure by increasing its common equity ratio to 45% from 42.69% in 2006 by the retention of earnings.

[26] A major input factor in the selection of return on common equity rates is business risk. As described in the rate application, business risk comes in the form of :

- The marketplace under which the utility operates;
- The nature of the utilities operations and energy supply;
- The regulatory risk faced by the utility; and
- The forecasting risk.

[27] The Company concludes that it is a higher risk utility than the other two investor-owned Atlantic Province electric utilities, Newfoundland Power and Nova Scotia Power. The Company provided the following actual return information for both investor-owned electric utilities:

Table 5

Earned Returns 2002 to 2004(%)

Year	Newfoundland Power	Nova Scotia Power
2002	10.7%	9.8%
2003	10.2%	10.4%
2004	10.3%	10.0%
2005	9.24%	9.8%
Average	10.11%	10.0%

[28] The Commission has reviewed the Company's submissions on this matter and agrees that the Company operates with a higher degree of business risk than other investor owned utilities in Atlantic Canada. This is due, in part, to the relative small size of the Company. In our view, this risk is, however, mitigated somewhat through the operation of the Energy Cost Adjustment Mechanism, which is discussed in more detail below.

[29] The Commission finds that a rate of return on average common equity of 10.25% is just and reasonable. This is viewed by the Commission as an upper limit or the maximum allowable return.

3.5 Deferred Costs Recoverable from Customers

[30] Section 47 of the *Electric Power Act* reads, in part, as follows:

> *47. (1) On and after January 1, 2004, Maritime Electric Company, Limited shall provide service in the province at the rates, tolls and charges, and on the terms and conditions of service, that were established and in effect under the former Act and the former regulations immediately before January 1, 2004 until such time as those rates, tolls and charges, and those terms and conditions of service, are altered or modified under this Act. 2003,c.3,s.23.*
>
> Annual report
>
> *(2) Prior to March 1, 2004, Maritime Electric Company, Limited shall provide an annual report to the Commission for the calendar year beginning January 1, 2003 that complies with the requirements of section 15. 2003,c.3,s.23.*
>
> Submission of proposed rates, tolls and charges
>
> *(3) Prior to May 1, 2004, Maritime Electric Company, Limited shall make a submission to the Commission under section 20 for the review and approval of its rates, tolls and charges. 2003,c.3,s.23.*
>
> Recovery of deferred costs, interest and unamortized expenses
>
> *(4) When approving or determining and fixing the rates, tolls and charges of Maritime Electric Company, Limited pursuant to a submission made under section 20 in accordance with subsection (3), or in accordance with any later application made in accordance with section 20, the Commission shall allow Maritime Electric Company, Limited*
>
> *(a) to recover, over such period of time and on such terms and conditions as the Commission considers just and reasonable,*
>
> *(i) the deferred costs that Maritime Electric Company, Limited would have been able to recover under the former Act and the former regulations,*
>
> *(ii) the unamortized portion of any deferred cost incurred before January 1, 2004 by Maritime Electric Company, Limited in respect of any power purchase agreement, and*
>
> *(iii) a reasonable return on the unrecovered deferred costs referred to in subclauses (i) and (ii); and*
>
> *(b) to recover, as an annual expense, the amounts payable by Maritime Electric Company, Limited pursuant to any power purchase agreement Maritime Electric Company, Limited has entered into before January 1, 2004 that continues in force on and after that date. 2003,c.3,s.23.*

[31] Commission Order UE05-01 approved the recovery of deferred costs in the amount of $1,500,000 in 2004 and $2,500,000 in 2005. This leaves $13,983,600 yet to be recovered from rates. Maritime Electric is requesting that a further $1,500,000 be recovered in 2006 and $1,300,000 in 2007. These are the amounts included in the proposed rates.

[32] Although the Commission has not, to date, defined the time period over which the remainder of the deferred account must be amortized or recovered through rates, the Commission believes that it is time to do so. We will, however, give the Company an opportunity to make a submission before doing

so. The Commission will order the filing of such a submission before the end of 2006. The proposed amount for 2006 will, however, be allowed. A decision on the 2007 amount will be deferred pending the filing of the above submission.

3.6 Proposed Rates

[33] A summary of current and proposed basic rates is summarized in Table 6.

Table 6

Basic Rates	Present Rates	Proposed Rates July 1, 2006
Residential Service Rate Schedule		
Residential Urban	$21.55	$22.27
Residential Rural	$23.60	$24.39
Residential Energy Charge for first 1200kWh/billing period	$0.1033/kWh	$0.1068/kWh
General Service Rate Schedule		
General Service 1	$21.55	$22.27
General Service Energy Charge		
Demand Charge (first 20kW no charge)	$11.78/kW	$12.17/kW
Energy Charge - first 5000kWh	$0.1291/kWh	$0.1334/kWh
Energy Charge - balance of kWh	$0.0813/kWh	$0.0840/kWh

[34] Maritime Electric states that the proposed 3.35% basic rate increase will be largely offset on July 1, 2006 due to the effects of the Energy Cost Adjustment Mechanism ("ECAM"). The Company states that the overall impact on a Rural Residential customer on July 1, 2006 using 650kWh per month (including GST) is a total increase of 1.6%. The following table illustrates the proposed rate increase for the average rural residential customer.

Table 7

Rural Residential Billing Comparison **Base charge and Energy charge**	July 1, 2005	July 1, 2006	July 1, 2007	Dec.31/07
Basic Service Charge	$23.60	$24.39	$24.39	$24.39
Energy charge (650KWh)	67.15	69.42	69.42	69.42
Subtotal	90.75	93.81	93.81	93.81
GST(6%)	5.44	5.63	5.63	5.63
Total	96.19	99.44	99.44	99.44
Base service charge and energy rate increase	3.35% →		0.00% →	

[35] In 2004, the Company applied for, and received Commission approval of, the present ECAM. The ECAM provides a mechanism that automatically adjusts monthly billings to customers to reflect changes in defined energy related costs.

[36] Without a mechanism to adjust for variations in energy supply costs, the Company's earnings would, in theory, fluctuate beyond reasonable ranges, resulting in the need for frequent Commission hearings. Maritime Electric

maintains that the ECAM, in its present form, provides stability to the Company resulting in reduced basic rates. For example, an increase or decrease in energy costs of $2,000,000—or approximately 3%—would see a variation of approximately 15% in the Company earnings. According to the Company, debt holders and shareholders would demand higher returns to offset this volatility. Maritime Electric maintains that the stability associated with this adjustment mechanism eliminates the need for frequent and costly rate hearings.

[37] Commission Order UE05-05, dated March 16, 2005, approved the interim and transitional ECAM currently in effect. Order UE05-06, dated June 24, 2005, ordered the replacement of the current ECAM with one containing fewer accounts. The transition to a new ECAM was to take effect on July 1, 2006.

[38] During 2004 and 2005, the ECAM was the subject of an independent study carried by consultant John Murphy. The Murphy study recommended a number of changes to the ECAM which were commented upon by the Company. In summary, Murphy recommended:

(1) That certain expense classifications that should be excluded from the ECAM; and
(2) that volume level changes in total purchased power should be excluded from the ECAM.

[39] Maritime Electric now requests that the Commission delay any changes to the ECAM pending receipt and review:

(1) of a depreciation study and cost allocation study ordered by the Commission, by Order UE06-02, to be filed in the summer-fall of 2006;
(2) of new energy supply agreements; and
(3) of the refurbishment costs associated with the Point Lepreau nuclear generating station.

[40] The Commission agrees with Maritime Electric that the pending studies will have implications on the ECAM. As a result, the Commission will, for now, order the continuation of the interim and transitional ECAM currently in effect.

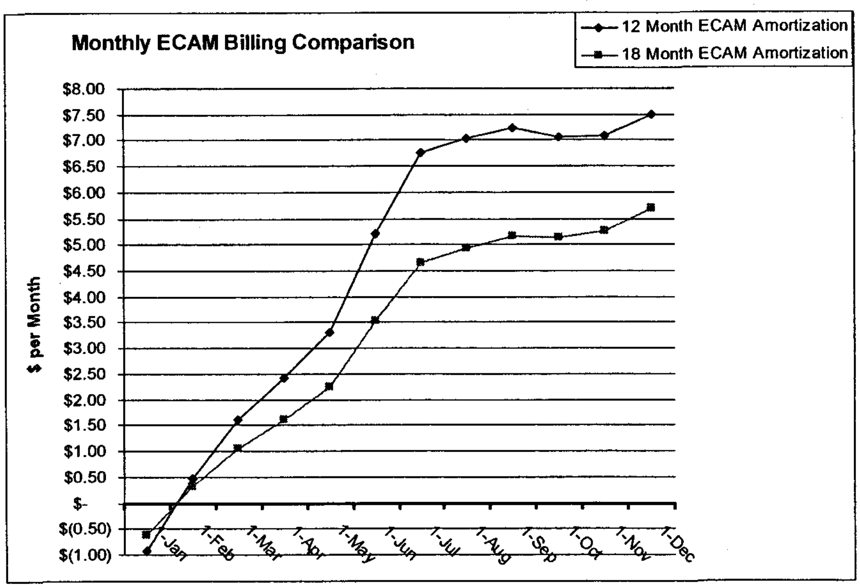
[41] The Commission has reviewed the forecasted impact the monthly ECAM charges will have on consumer electricity charges for 2006 and 2007. Currently, customers are enjoying the benefits of an ECAM adjustment that reduces monthly customer bills. The main reason for this lies in the present energy supply contracts negotiated several years ago when energy was less expensive and denominated in US dollars. The appreciating Canadian dollar has assisted in reducing the costs of purchased energy.

[42] It is unlikely that Maritime Electric will, in future, be immune from rising energy costs experienced by all jurisdictions. New energy supply contracts will

no doubt be more expensive than current agreements and will be based on a higher valued Canadian dollar.

[43] The Commission is concerned about the impact of rising ECAM adjustments and the rising balance of the ECAM account due to the 18 month amortization of energy costs. Deferring energy costs to a future period when costs are rising will place further burden on customers. The Commission is of the view that utility energy costs should be recovered within the year the energy is used. As an alternative, the Commission has considered an ongoing 12 month amortization period. This results in a higher recovery of ECAM charges as shown by the following figure which compares amortizations periods of 18 months and 12 months, commencing in January of 2007. The figure depicts the change in the bill of a residential customer who consumes 650 kWh per month.

Figure 1



[44] The ECAM balance to be recovered from customers using the currently authorized 18 month amortization period spreads the ECAM recovery over a longer period of time. The Company is owed this money and it appears as an account receivable on year-end financial statements. A 12 month amortization period, commencing on January 1, 2007, would recover these energy charges from customers faster and the Company is owed less money at year end. The following table shows the comparison.

Table 8

Unrecovered post 2003 costs recoverable	Actual 2004	Actual 2005	Forecast 2006	Forecast 2007
18 month amortization	$2,725,400	($3,343,488)	$1,675,800	$14,832,200
12 month amortization	n/a	n/a	$1,675,800	$12,305,781

[45] Thus, an additional $2,526,419 would be collected from customers with the 12 month amortization period. The impact to customer monthly billing for the average residential customer using 650kWh of electricity monthly is shown on Table 9.

Table 9

Residential Billing Comparison Forecast ECAM adjustment	July 1, 2005	July 1, 2006	July 1, 2007	Dec.31, 2007
Forecast monthly ECAM adjustment (650kWh)	0.98	-2.51	5.21	7.50
GST(6%)	0.06	-0.15	0.31	0.45
ECAM adjustment plus GST	1.04	-2.66	5.52	7.95

[46] The Commission finds that a 12-month amortization period better represents the true costs to the consumer. The Commission will order an amendment to the ECAM to reflect the implementation of 12-month amortization period effective in January, 2007.

4. Disposition

[47] An order will therefore issue implementing the findings and conclusions contained in these reasons.

IN THE MATTER of an application by Maritime Electric Company, Limited for approval of proposed amendments to its rates.

Order

UPON receiving an application by Maritime Electric Company, Limited (the "Company") for approval of proposed amendments to its rates;

AND UPON considering the application as well as the evidence of the Company and responses to staff interrogatories;

NOW THEREFORE, for the reasons given in the annexed Reasons for Order;

IT IS ORDERED THAT

1. the requested increase in basic rates and charges is approved in accordance with Appendix 1 contained in the application for effect with meter readings taken on and after July 1, 2006;
2. the current interim and transitional Energy Cost Adjustment Mechanism ("ECAM") shall continue in effect pending receipt and review of certain studies and filings described in the within Reasons for Order;
3. the amortization period of 18 months contained in the ECAM shall be changed to 12 months, effective January 1, 2007;
4. the maximum allowed return on average common equity is set at 10.25 percent;
5. the Company shall continue the amortization of the December 31, 2003 deferred costs recoverable from customers in the amount of $1,500,000 in 2006 with the balance to be recovered over such time and in such annual amounts as the Commission will further order; and

6. the Company shall prepare a report setting out options for the full recovery of the remaining deferred costs in equal annual amounts with the said report to be filed with the Commission by December 31, 2006.

DATED at Charlottetown, Prince Edward Island, this 27th day of June, 2006.

BY THE COMMISSION:

(Sgd) *Maurice Rodgerson*

Maurice Rodgerson, Chair

(Sgd) *Weston Rose*

Weston Rose, Commissioner

(Sgd) *James Carragher*

James Carragher, Commissioner

(Sgd) *Anne Petley*

Anne Petley, Commissioner

NOTICE

Section 12 of the *Island Regulatory and Appeals Commission Act* reads as follows:

> *12. The Commission may, in its absolute discretion, review, rescind or vary any order or decision made by it or rehear any application before deciding it.*

Parties to this proceeding seeking a review of the Commission's decision or order in this matter may do so by filing with the Commission, at the earliest date, a written Request for Review, which clearly states the reasons for the review and the nature of the relief sought.

Sections 13.(1) and 13(2) of the *Act* provide as follows:

> *13.(1) An appeal lies from a decision or order of the Commission to the Appeal Division of the Supreme Court upon a question of law or jurisdiction.*
>
> *(2) The appeal shall be made by filing a notice of appeal in the Supreme Court within twenty days after the decision or order appealed from and the Civil Procedure Rules respecting appeals apply with the necessary changes.*

IRAC140A(04/07)

Gaz Metro, Decision (French), D-2004-196, September 2004

D É C I S I O N

QUÉBEC **RÉGIE DE L'ÉNERGIE**

D-2004-196	R-3529-2004	24 septembre 2004

PRÉSENTS :

Jean-Noël Vallière, B. Sc. (Écon.)
Anita Côté-Verhaaf, M. Sc. (Écon.)
Francine Roy, MBA

Régisseurs

Société en commandite Gaz Métro (SCGM)

Demanderesse

et

Intervenants dont les noms apparaissent à la page suivante

Demande de modifier les tarifs de SCGM à compter du 1er octobre 2004

Intervenants :

- Association des consommateurs industriels de gaz (ACIG);
- Fédération canadienne de l'entreprise indépendante (FCEI);
- Groupe de recherche appliquée en macroécologie (GRAME);
- Hydro-Québec;
- Option consommateurs (OC);
- Regroupement national des Conseils régionaux de l'environnement du Québec (RNCREQ);
- Regroupement des organismes environnementaux en énergie (ROEÉ);
- Stratégies énergétiques et Association québécoise de lutte contre la pollution atmosphérique (SÉ/AQLPA);
- TransCanada Energy Ltd;
- Union des consommateurs (UC);
- Union des municipalités du Québec (UMQ).

TABLE DES MATIÈRES

1. INTRODUCTION

Le 10 mars 2004, Société en commandite Gaz Métro (SCGM) introduit à la Régie de l'énergie (la Régie) une demande de modification de ses tarifs à compter du 1er octobre 2004.

Le 29 avril 2004, par sa décision D-2004-88, la Régie permet la mise en place d'un Groupe de travail, fixe les lignes directrices pour le processus d'entente négociée (PEN) et détermine les sujets référés au PEN et ceux devant être étudiés en audience.

Le 5 mai 2004, SCGM dépose à la Régie la preuve sur le renouvellement du mécanisme automatique d'ajustement du taux de rendement et sur tous les sujets d'audience. Elle demande également une ordonnance de confidentialité pour les pièces SCGM-4, document 1, section 8 (Optimalité de la structure d'équilibrage) et SCGM-4, document 9 (Comparaison des coûts entre les structures d'équilibrage réalisables).

Le 10 juin 2004, la Régie rend la décision D-2004-117 dans laquelle elle accorde la confidentialité demandée par SCGM. Le Groupe de travail dépose, pour sa part, son rapport final.

Le 5 juillet 2004, le distributeur demande, par lettre, l'autorisation à la Régie de créer un compte de frais reportés pour y inclure un montant remboursable aux clients de 88 000 $ représentant l'impact net de la disposition des comptes de frais reportés et des modifications tarifaires des taux de Union Gas Limited (Union Gas) sur les tarifs d'équilibrage de SCGM.

Le 27 juillet 2004, le distributeur transmet à la Régie une demande d'autorisation de modifier immédiatement les taux du tarif de transport et de créer un compte de frais reportés pour le montant de réduction de 53 000 $ au prix du service d'équilibrage. Cette demande fait suite à l'ordonnance AO-1-TGI-07-2003 de l'Office national de l'énergie (ONÉ), laquelle modifie les tarifs de TransCanada Pipelines Limited sur une base provisoire à compter du 1er août 2004. La disposition de ces comptes de frais reportés se fera dans le présent dossier. Le 5 août 2004, la Régie acquiesce à la demande de SCGM, conformément aux modalités approuvées par la décision D-2001-232[1].

L'audience se tient les 17 et 18 août 2004 et le dossier est pris en délibéré le 31 août 2004, date de la réception de la demande amendée et des pièces modifiées pour tenir compte des

[1] Dossier R-3463-2001, 27 septembre 2001.

effets de la décision de l'ONÉ ainsi que de la mise à jour relative aux taux obligataires long terme et au taux d'inflation conformément à l'entente sur le mécanisme incitatif.

2. CONCLUSIONS RECHERCHÉES

Les conclusions recherchées dans la demande réamendée de SCGM, en date du 31 août 2004, sont les suivantes :

> « ***RECONDUIRE*** *jusqu'au 30 septembre 2006 les programmes et conditions tarifaires suivants déjà reconduits jusqu'au 30 septembre 2005 par la décision D-2003-180 : 1) programme de flexibilité tarifaire bi-énergie; 2) programme de flexibilité tarifaire mazout pour les clients des tarifs D1, D3 et DM;*
>
> ***APPROUVER****, à compter du 1er octobre 2004, les modifications proposées à certaines conditions d'applications des programmes de rabais à la consommation et de rétention par voie de rabais à la consommation (P.R.C. et P.R.R.C.);*
>
> ***APPROUVER****, à compter du 1er octobre 2004, le programme additionnel alternatif à l'actuel programme commercial axé sur le financement (« PCAF »), tel que décrit à la pièce SCGM-2, document 7;*
>
> ***APPROUVER*** *le plan d'approvisionnement de SCGM pour l'exercice 2005, tel que décrit à pièce SCGM-4, document 1, conformément à l'article 72 de la Loi;*
>
> ***APPROUVER****, pour l'exercice financier 2005, les modifications proposées au « Programme de produits financiers dérivés, les volumes totaux pouvant être protégés en vertu de ce programme ainsi que le plafond applicable aux contrats d'échange à prix fixes »;*
>
> ***APPROUVER*** *l'application à l'exercice 2005 du mécanisme incitatif à l'amélioration à la performance approuvé par la Régie dans sa décision D-2004-51;*
>
> ***AUTORISER*** *l'utilisation des sommes imputées au Fonds d'efficacité énergétique (FEÉ) conformément au plan d'action du FEÉ présenté à la pièce SCGM-9, document 8;*
>
> ***AUTORISER*** *le coût en capital moyen de 9,01% sur la base de tarification pour l'exercice financier 2005, lequel provient, entre autres, de l'application du mécanisme automatique d'établissement du taux de rendement sur l'avoir moyen des actionnaires énoncé dans les décisions D-99-11, D-99-150 et D-2003-180 dont SCGM propose la reconduction pour les exercices 2005, 2006 et 2007, ainsi que d'une bonification résultant de l'application du mécanisme incitatif à l'amélioration de la performance approuvé dans la décision D-2004-51;*

***AUTORISER**, dans l'évaluation des projets d'investissements prévus par SCGM pour l'exercice financier 2005, le coût en capital prospectif de 7,04% résultant de l'utilisation des taux déterminés selon les paramètres contenus dans la décision D-97-25;*

***MODIFIER**, à compter du 1er octobre 2004, les tarifs de SCGM de façon à ce qu'ils génèrent les revenus requis totalisant 794 125 000 $, de façon à permettre à SCGM de récupérer l'ensemble de ses coûts pour assumer ses services;*

***AUTORISER** la répartition tarifaire proposée à la pièce SCGM-12, document 6;*

***APPROUVER** le texte des tarifs proposé à la pièce SCGM-13, document 1.* »

3. REVENU REQUIS

Le dossier tarifaire 2005 est le premier à être préparé selon les termes du mécanisme incitatif approuvé par la Régie dans la décision D-2004-51[2]. Ce mécanisme ne diffère pas fondamentalement de celui qui était appliqué depuis le 1er octobre 2000.

Le fonctionnement du mécanisme de rendement incitatif à l'amélioration de la performance de SCGM est basé sur une comparaison entre le revenu plafond découlant de l'application du mécanisme incitatif et le revenu requis, tel qu'il aurait été établi selon la méthode du coût de service. En début d'exercice, dans le cas ou le revenu requis est inférieur au revenu plafond, l'écart favorable, considéré comme un gain de productivité, est partagé avec les clients dans la proportion de 50 % pour ces derniers et de 50 % pour SCGM à titre de bonification du rendement de base sur l'avoir des actionnaires ordinaires.

Le tableau 1 présente le calcul du gain de productivité applicable pour l'année témoin 2004-2005 et son partage ainsi que le revenu plafond et le revenu requis selon les composantes distribution (D), inventaires (F, C, T), transport (T) et équilibrage (É).

---

2 Décision D-2004-51, dossier R-3494-2002, 3 mars 2004.

TABLEAU 1
Calcul du gain de productivité et son partage
(000 $)

	2003-2004	2004-2005				
	TOTAL	**Distribution (D)**	**Inventaires* (F, C, T)**	**Transport (T)**	**Équilibrage (É)**	**TOTAL**
Revenu plafond	770 363	461 577	14 605	248 189	87 595	811 966
Revenu requis (avant partage)	743 797	425 896	14 605	248 189	87 595	776 285
Gain de productivité	26 566	35 681	-	-	-	35 681
Part des clients 50 %**	12 619	17 841	-	-	-	17 841
Part de SCGM 50 %**	13 947	17 841	-	-	-	17 841
Rendement additionnel de SCGM après impôts	1,52 %	1,95 %	-	-	-	1,95 %

* La composante inventaires (F, C, T) représente les coûts directement reliés au maintien des inventaires se rapportant aux services de fourniture de gaz naturel, de gaz de compression et de transport.
** En 2003-2004, la part des clients était de 47,5 %, celle de SCGM était de 52,5 %.

Source : Pièces SCGM-8, documents 1, 2 et 3 et SCGM-12, documents 2 et 3.

Le revenu plafond est établi à partir de celui de l'exercice antérieur, lequel est ajusté pour tenir compte de la variation des volumes projetés et de l'évolution des prix à la consommation (IPC Québec) de 1,51 %[3] moins un facteur de productivité de 0,5 %. Le revenu plafond, qui est comparé au revenu requis, est ajusté pour tenir compte de l'impact des facteurs exogènes et des exclusions. Le revenu plafond des autres composantes est égal au revenu requis déterminé selon la méthode du coût de service.

Le revenu requis de distribution est établi en suivant le même procédé que dans un mode de réglementation par les coûts. Les coûts de distribution sont principalement constitués des dépenses d'exploitation et du rendement sur la base de tarification de la composante distribution. Les coûts de transport et d'équilibrage sont en majeure partie déterminés par les contrats conclus avec les fournisseurs des services de transport et d'entreposage et les volumes projetés.

[3] Pièce SCGM-8, document 1, page 1.

La part de SCGM du gain de productivité, 17 841 000 $, représente une bonification après impôts de 1,95 %[4] du taux de rendement de base sur l'avoir des actionnaires ordinaires.

3.1 BASE DE TARIFICATION

Pour l'exercice financier 2005, SCGM projette une base de tarification moyenne de 1 674 777 000 $. Les additions à la base de tarification s'élèvent à 145 648 000 $. Elles sont présentées sous deux rubriques générales : les frais reportés pour un total de 31 031 000 $ et les immobilisations, regroupées sous cinq catégories, pour un total de 114 617 000 $ conformément à l'article 5 du R*èglement sur les conditions et les cas requérant l'autorisation de la Régie de l'énergie*[5].

Développement et renforcement du réseau

Pour le développement du réseau, SCGM prévoit investir 44 565 000 $ ventilés de la façon suivante : 3 769 000 $ pour des projets d'extension subventionnés dont le coût est supérieur à 1,5 M$, 15 429 000 $ pour des projets de raccordement sur réseau et 25 366 000 $ pour des projets de raccordement hors réseau[6]. Pour le renforcement du réseau, un montant de 14 210 000 $ est projeté dont 9 510 000 $ pour l'enlèvement et la relocalisation de la conduite située sous le pont Jacques-Cartier.

Amélioration des réseaux de distribution et de transmission

Afin d'assurer la fiabilité du service de distribution du gaz et la sécurité du réseau, SCGM prévoit des investissements de 17 233 000 $ pour l'amélioration du réseau et de 545 000 $ pour le raccordement et la régularisation du réseau de transmission.

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4 Pièce SCGM -8, document 3, page 1.
5 (2001) 133, G.O. II, 6165.
6 Pièce SCGM -6, document 3, page 10.

Entreposage du gaz

Le distributeur propose d'investir 895 000 $ pour l'entreposage du gaz. Cet investissement est nécessaire afin d'effectuer des mises à niveau aux normes de l'Association canadienne de normalisation, d'assurer la fiabilité et la sécurité entourant l'usine de liquéfaction et d'améliorer les procédés.

Installations générales

SCGM prévoit des investissements de 28 598 000 $ afin d'assurer l'entretien et l'amélioration des autres installations.

Frais généraux capitalisés

Ces investissements de 8 571 000 $ correspondent aux frais généraux encourus pour la réalisation des investissements ci-dessus mentionnés.

3.2 TAUX MOYEN DU COÛT DU CAPITAL

Le taux de rendement sur la base de tarification correspond au coût moyen pondéré des différentes composantes de la structure de capital. SCGM utilise, pour l'exercice financier 2005, une structure de capital constituée de 38,5 % d'avoir des actionnaires ordinaires, de 7,5 % d'actions privilégiées et de 54 % de dette. Le taux moyen du coût en capital, avant partage du gain de productivité, est de 8,26 %. Ce taux comprend, entre autres, un coût moyen de la dette de 7,697 % et un taux de rendement sur l'avoir des actionnaires ordinaires de 9,69 %, avant bonification[7]. Après bonification, le taux de rendement demandé s'établit à 11,64 % sur l'avoir des actionnaires ordinaires et à 9,01 % sur la base de tarification[8].

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7 Pièce SCGM-7, document 2, page 1.

8 *Ibid.* à la page 2.

3.3 DEMANDE DE RECONDUCTION DU MÉCANISME D'AJUSTEMENT AUTOMATIQUE DU TAUX DE RENDEMENT ET DE LA STRUCTURE DE CAPITAL

3.3.1 PREUVE DE SCGM

Mécanisme d'ajustement automatique du taux de rendement

SCGM demande à la Régie de reconduire, pour une période de trois ans, jusqu'à l'année tarifaire 2006-2007 inclusivement, le mécanisme d'ajustement automatique du taux de rendement sur l'avoir des actionnaires ordinaires ainsi que la structure de capital.

SCGM reconnaît que le mécanisme incitatif en vigueur depuis l'année 2000 a généré un taux de rendement supérieur au taux de rendement de base établi en vertu du mécanisme d'ajustement automatique. SCGM soumet qu'il est important de dissocier le taux de rendement de base établi à partir de la formule d'ajustement automatique du taux de rendement bonifié obtenu par l'application du mécanisme incitatif. Le taux de base représente un taux de rendement à être octroyé par la Régie afin de rencontrer les différents facteurs énumérés plus bas. Le mécanisme incitatif vient rémunérer SCGM pour une performance supérieure à la performance attendue dans le mode traditionnel de réglementation. Combiner le résultat du mécanisme incitatif avec la formule d'ajustement automatique du taux de rendement reviendrait, selon SCGM, à lui demander de cesser ses efforts de développement et d'amélioration de la productivité[9].

Dans le présent dossier, SCGM ne vise pas à justifier la formule. Cela a déjà été fait dans le dossier R-3397-98 et dans la décision D-99-11. Dans cette décision, la Régie approuvait un mécanisme d'ajustement automatique du taux de rendement basé sur les variations des taux obligataires sans risque en tenant compte des facteurs suivants :

- contexte financier de l'entreprise et son risque d'entreprise;
- contexte économique général;
- taux d'intérêt et rendement des obligations de long terme;
- méthodes d'estimation du taux de rendement présentées par les experts et contexte réglementaire dans les juridictions voisines;
- maintien de l'intégrité financière de l'entreprise.

[9] Notes sténographiques (NS), volume 1, pages 50 et 51.

L'approche de SCGM consiste à reprendre les différents éléments sur lesquels repose cette décision, à en suivre l'évolution depuis 1999 et à démontrer qu'ils n'ont pas, globalement, changé de façon significative. Par conséquent, la formule peut être qualifiée de raisonnable encore aujourd'hui.

Structure de capital

SCGM souhaite la reconduction de sa structure de capital. Pour appuyer sa demande, SCGM réfère à la décision D-96-31 de la Régie du gaz naturel, notamment aux passages suivants :

> « *La Régie est d'avis également qu'on ne peut modifier fréquemment ou subitement la structure de capital d'une entreprise car cela pourrait créer une instabilité financière qui pourrait inquiéter les investisseurs.*
>
> […] *à moins de circonstances exceptionnelles qui le justifieraient, on ne remettra pas en cause à chaque année cette structure que la Régie juge optimale, et qui respecte les principes qui l'ont guidée dans sa décision, à savoir: assurer à long terme un coût de capital le plus bas possible, et maintenir la santé financière du distributeur.* »[10]

Selon le distributeur, la preuve présentée en appui à la demande de reconduction du mécanisme d'ajustement automatique du taux de rendement est transposable à la demande de maintien de la structure de capital. La conclusion est similaire étant donné qu'aucune circonstance exceptionnelle n'est survenue depuis 1999 qui justifierait la remise en question de la structure de capital.

3.3.2 POSITION DE L'ACIG

Seule l'ACIG s'est prononcée sur la proposition de SCGM. Bien que l'intervenante ne partage pas totalement l'ensemble des éléments de preuve du distributeur dans sa demande, elle considère, pour l'instant, inutile d'approfondir l'analyse de cette question, compte tenu du fait que le distributeur ne propose pas de modifications à la formule actuelle[11].

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[10] Décision D-96-31, dossier R-3351-96, 9 octobre 1996, page 67.
[11] Plaidoirie écrite de l'ACIG, pages 6 et 7.

3.4 OPINION DE LA RÉGIE

Sur l'application du mécanisme incitatif

La Régie note que les participants au Groupe de travail sont d'avis que les pièces produites par SCGM respectent le mécanisme incitatif à l'amélioration de la performance approuvé dans la décision D-2004-51 et permettent, en conséquence, à la Régie de fixer les tarifs de SCGM à compter du 1er octobre 2004[12]. Bien que SÉ/AQLPA ait réservé ses droits de faire des représentations sur les documents SCGM-9, documents 2 et 9[13], il ne remet pas en question le niveau du revenu requis.

La Régie constate que l'entente déposée par le Groupe de travail est conforme à l'application du mécanisme incitatif et l'approuve.

Sur la demande de reconduction du mécanisme d'ajustement automatique du taux de rendement et de la structure de capital

La Régie juge que globalement les facteurs retenus dans la décision D-99-11 n'ont pas changé d'une manière significative, notamment ceux ayant trait aux contextes économique, d'affaires et financier. Par conséquent, elle approuve la demande de SCGM de reconduire le mécanisme d'ajustement automatique du taux de rendement pour une période de trois ans, soit jusqu'à l'année tarifaire 2006-2007 inclusivement et de maintenir la structure de capital.

4. BAISSE TARIFAIRE

Les tarifs sont fixés de manière à générer le revenu plafond moins la part des clients du gain de productivité, nette des sommes investies dans le Fonds en efficacité énergétique (FEÉ).

Cette année, les clients petit et moyen débits n'ont pas eu à contribuer au FEÉ parce que les revenus d'intérêt du FEÉ de l'année tarifaire précédente (sur la base de sept mois réels et cinq mois projetés) ont excédé les fonds engagés pour l'année tarifaire précédente (toujours sur la base de sept mois réels et cinq mois projetés).

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[12] Rapport du Groupe de travail, pièce SCGM -1, documents 3 et 4.

[13] Les rapports de suivi et les tableaux financiers du Plan global d'efficacité énergétique (PGEÉ) et le Compte d'aide à la substitution d'énergies plus polluantes (CASEP).

La baisse tarifaire demandée est obtenue en comparant le revenu requis, après partage, au revenu obtenu en appliquant les tarifs en vigueur aux volumes projetés pour l'année témoin 2004-2005.

Cette baisse globale de 1,19 % est le résultat net de la baisse du revenu requis des composantes distribution et inventaires ainsi que de la hausse du revenu requis des composantes transport et équilibrage. La baisse de la composante distribution s'établit à 3,01 %. Le tableau 2 présente le détail.

TABLEAU 2
Calcul de l'ajustement tarifaire global
(000 $ et en %)

	Distribution (D)	Inventaires (F, C, T)	Transport (T)	Équilibrage (É)	TOTAL
Revenu plafond	461 577	14 605	248 189	87 595	811 966
Part des clients	(17 841)				(17 841)
FEÉ	S. O.				--
Revenu requis (après partage)	443 736	14 605	248 189	87 595	794 125
Tarifs 2003-2004*	453 380	15 429	244 226	86 605	799 640
	(9 644)	(824)	3 963	990	(5 515)
Remboursement FEÉ	(4 000)				(4 000)
Ajustement tarifaire	(13 644)	(824)	3 963	990	(9 515)
Pourcentage	-3,01 %	-5,34 %	1,62 %	1,14 %	-1,19 %

* Tarifs en vigueur en 2003-2004 appliqués aux volumes projetés pour l'année témoin 2004-2005.
Source : Pièce SCGM-8, document 4, page 1.

4.1 STRATÉGIE TARIFAIRE POUR RÉPARTIR LA BAISSE

De façon générale, l'ajustement tarifaire requis des inventaires (F, C, T) de même que des services de transport et d'équilibrage a été réparti au prorata des volumes correspondant au service fourni à la classe tarifaire.

L'ajustement tarifaire à la baisse applicable à la composante distribution s'élève à 13,644 M$. La majeure partie de ce montant, 13,753 M$, est attribuable aux coûts de distribution excluant ceux découlant du traitement des trop-perçus antérieurs, du PGEÉ et du FEÉ.

Exception faite des coûts du PGEÉ qui sont répartis selon la méthode d'allocation approuvée dans la décision D-2001-232, tous les autres coûts sont répartis uniformément en pourcentage des revenus de distribution de la classe tarifaire. Les coûts du FEÉ n'affectent que les clients des tarifs de distribution D_1, D_3 et D_M[14]. Les clients bénéficiant du tarif fixe de distribution ne sont touchés par aucun des ajustements.

Une fois cette répartition complétée, les grilles tarifaires doivent être modifiées pour refléter la réduction appliquée aux rabais transitoires. Par la suite, les grilles tarifaires du service de distribution sont ajustées pour intégrer les modifications proposées aux méthodes d'allocation des coûts de transport et d'équilibrage ainsi que les modifications aux structures tarifaires.

4.2 MODIFICATIONS AUX MÉTHODES D'ALLOCATION DES COÛTS DE TRANSPORT ET D'ÉQUILIBRAGE

Dans sa décision D-2003-180[15], la Régie demandait au distributeur d'évaluer s'il y avait lieu de réviser les éléments suivants en regard du nouveau contexte gazier :

- méthode de répartition des coûts de transport;
- fonctionnalisation entre la pointe et l'espace pour les coûts d'équilibrage;
- pointe pour les clients en service interruptible.

Le distributeur juge qu'il y a lieu de modifier les deux derniers éléments et fait de nouvelles propositions.

[14] Pièce SCGM-12, document 6.
[15] Dossier R-3510-2003, 26 septembre 2003.

4.2.1 MÉTHODE DE RÉPARTITION DES COÛTS DE TRANSPORT

En ce qui concerne la méthode de répartition des coûts de transport, le distributeur mentionne que son positionnement stratégique procure des bénéfices au niveau des coûts d'équilibrage et estime que la répartition demeure adéquate dans le contexte actuel.

4.2.2 FONCTIONNALISATION ENTRE LA POINTE ET L'ESPACE POUR LES COÛTS D'ÉQUILIBRAGE

Le distributeur propose une nouvelle méthodologie se basant sur les consommations journalières historiques de la dernière année.

Dans un premier temps, il détermine un ordre de priorité d'utilisation des différents outils d'équilibrage dont il dispose et les superpose. Le débit journalier potentiel atteint par chaque outil est ensuite comparé aux paramètres consommation journalière moyenne annuelle (A), consommation journalière moyenne de l'hiver (H) et consommation journalière de pointe (P).

La part des volumes du débit journalier entre A et H est fonctionnalisée en espace et celle entre H et P est fonctionnalisée en pointe. Pour cette opération, les consommations réelles pour chacune des journées de l'année sont utilisées.

La proposition a pour effet d'augmenter la proportion fonctionnalisée sous la pointe de 18 % à 41 % et de diminuer celle sous l'espace de 82 % à 59 %. L'impact de cette modification sur les revenus d'équilibrage est présenté ci-dessous.

TABLEAU 3
Impact de la fonctionnalisation entre la pointe et l'espace sur les revenus
Budget 2003-2004 – (000 $)

	Revenu d'équilibrage			Revenu de transport, d'équilibrage et de distribution	
Tarif de distribution (D)	**Méthode actuelle** (1)	**Méthode proposée** (2)	**Écart** (3)=(2)-(1)	**Revenu** (4)	**%** (5)=(3)/(4)
1	67 919	70 621	2 702	497 119	0,5 %
M	10 583	12 567	1 984	86 184	2,3 %
3	624	741	118	12 334	1,0 %
4	2 113	2 349	236	115 318	0,2 %
5 volet 1A	-2 319	-5 441	-3 222	38 728	-8,3 %
5 volet 1B	1 331	-485	-1 816	12 676	-14,3 %

Source : Pièce SCGM-11, document 1, page 9.

4.2.3 POINTE POUR LES CLIENTS EN SERVICE INTERRUPTIBLE

Le distributeur propose de revoir l'hypothèse d'une pointe à zéro pour les clients interruptibles puisque ces derniers, en particulier les clients du volet 1B, utilisent une part des outils de pointe. Il mentionne que les clients interruptibles ne doivent pas se voir allouer une pointe équivalente à celle des clients continus en raison du service de qualité moindre que reçoivent les clients interruptibles.

Le distributeur propose d'utiliser une fraction de la pointe pour les clients du tarif D_5 basée sur le nombre de jours de pointe où ces clients sont présents. Le distributeur évalue que durant l'hiver, il y a 70 jours où les outils de pointe sont utilisés. Il détermine le pourcentage qui devrait être attribué aux clients interruptibles en prenant le nombre de jours maximum affiché au texte des tarifs par rapport à ces 70 jours.

Ainsi, les clients du tarif D_5 volet 1A ne se voient pas attribuer de pointe puisque leur nombre de jours d'interruption maximum est supérieur à ces 70 jours. Pour leur part, les clients du tarif D_5 volet 1B se voient attribuer une pointe proportionnelle au nombre de jours de pointe où ils sont présents.

L'impact de cette proposition est illustré au tableau suivant.

TABLEAU 4
Impact de l'application d'une pointe à l'interruptible
Budget 2003-2004 – (000 $)

	Revenu d'équilibrage			**Revenu de transport, d'équilibrage et de distribution**	
Tarif de distribution (D)	**Méthode actuelle** (1)	**Méthode proposée** (2)	**Écart** (3)=(2)-(1)	**Revenu** (4)	**%** (5)=(3)/(4)
1	67 919	67 194	-725	497 119	-0,1 %
M	10 583	10 418	-165	86 184	-0,2 %
3	624	614	-10	12 334	-0,1 %
4	2 113	2 086	-28	115 318	0,0 %
5 volet 1A	-2 319	-2 190	129	38 728	0,3 %
5 volet 1B	1 331	2 129	798	12 676	6,3 %

Source : Pièce SCGM-11, document 1, page 14.

4.3 MODIFICATIONS AUX STRUCTURES TARIFAIRES

4.3.1 PRINCIPALES MODIFICATIONS

SCGM propose certaines modifications aux structures tarifaires. Plus spécifiquement les sujets abordés sont les suivants :

- ajustements reliés aux inventaires;
- service de fourniture – service fourni par le client;
- service d'équilibrage;
- service de distribution D_1 et D_M;
- structure tarifaire et efficacité énergétique ;
- texte des tarifs.

La nature, les modalités et les motifs sous-tendant ces modifications ainsi que, le cas échéant, leurs effets sont présentés à l'annexe 1.

4.3.2 EFFET SUR LES TARIFS

Le tableau 5 présente de façon globale l'effet de la stratégie tarifaire, des rabais transitoires ainsi que des modifications aux structures tarifaires.

TABLEAU 5
Répartition tarifaire[16]

	Revenus selon D-2003-180 2003- 2004 (000 $)					Revenus proposés 2004-2005 (000 $)				
Tarif	**Inventaire**	**Transport**	**Équilibrage**	**Distribution**	**TOTAL**	**Inventaire**	**Transport**	**Équilibrage**	**Distribution**	**TOTAL**
1	12 546	92 325	67 374	334 416	506 660	11 994	93 825	71 134	321 274	498 227
M	1 573	32 646	11 207	49 409	94 834	1 434	33 175	12 538	48 007	95 154
3	55	3 214	455	4 428	8 152	51	3 266	513	4 330	8 159
4	391	81 094	5 974	47 413	134 873	366	82 418	5 908	46 894	135 586
5	864	34 683	1 595	17 715	54 856	760	35 248	(2 485)	19 227	52 749
Ajustement*		264			264		264			264
TOTAL	15 429	244 226	86 605	453 380	799 640	14 605	248 196	87 607	439 732	790 139

* Ajustement inventaire transport

Source : Pièce SCGM-12, document 8, pages 1 et 4.

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16 Certaines données diffèrent légèrement d'un tableau à l'autre. Ces différences, déjà présentes dans les pièces au dossier, sont causées par l'arrondissement.

Les tarifs de distribution diminuent en moyenne de 3,01 %. Cette baisse tient compte du remboursement à partir du FEÉ de 4 M$ fait aux clients petit et moyen débits. Ce remboursement représente une partie des gains de productivité de ces clients affectée au FEÉ. La baisse se répartit comme suit :

- D1 - 3,9 %;
- DM - 2,8 %;
- D3 - 2,2 %;
- D4 - 1,1 %;
- D5 + 8,5 %.

La distribution n'est qu'une composante de la facture totale du client. En tenant compte des autres composantes (inventaires, transport, équilibrage), la baisse globale moyenne des tarifs est de 1,19 %. La baisse se répartit comme suit :

- tarif 1 - 1,7 %;
- tarif M + 0,3 %;
- tarif 3 + 0,1 %;
- tarif 4 + 0,5 %;
- tarif 5 - 3,8 %.

4.4 OPINION DE LA RÉGIE

4.4.1 SUR LA STRATÉGIE TARIFAIRE

La Régie accepte la stratégie tarifaire proposée. Elle est conforme à l'approche retenue dans le mécanisme incitatif.

4.4.2 MODIFICATIONS AUX MÉTHODES D'ALLOCATION DES COÛTS DE TRANSPORT ET D'ÉQUILIBRAGE

Sur la méthode de répartition du coût de transport

La Régie prend acte qu'il n'y a pas lieu de modifier la méthode de répartition des coûts de transport.

Sur la fonctionnalisation entre la pointe et l'espace pour les coûts d'équilibrage

La Régie juge que l'augmentation de la proportion des coûts fonctionnalisés sous la composante pointe et la diminution de celle fonctionnalisée sous la composante espace reflète plus adéquatement la structure contractuelle des coûts d'entreposage du distributeur que les proportions utilisées actuellement. Pour ce motif la Régie accepte la proposition.

Toutefois, la Régie souhaite que certains aspects soient approfondis dans le prochain dossier tarifaire notamment :

- l'utilisation de données réelles aux fins de la fonctionnalisation des outils d'équilibrage entre la pointe et l'espace (par exemple : l'effet sur la stabilité des tarifs d'équilibrage à travers le temps, le lien de causalité avec le plan d'approvisionnement);
- l'inclusion des consommations des clients en service interruptible dans l'évaluation des journées de pointe;
- la fonctionnalisation de la provision de pointe.

Sur la pointe pour les clients en service interruptible

En ce qui concerne l'attribution d'une pointe aux clients du tarif D_5, la Régie considère que la proposition permet de capter les coûts associés à la planification des outils d'équilibrage contractés pour desservir cette catégorie de clients. En ce sens, la proposition permet de mieux refléter la causalité des coûts au niveau des outils d'équilibrage et d'ajuster la tarification en conséquence. La Régie accepte donc la proposition du distributeur.

4.4.3 MODIFICATIONS AUX STRUCTURES TARIFAIRES

La Régie accepte les modifications proposées aux structures tarifaires ainsi que les changements au texte des tarifs tels qu'explicités aux pièces SCGM-11, document 2 et SCGM-13, document 1.

La Régie relève que les ajustements à la méthode de tarification de l'équilibrage ont été, dans une large mesure, envisagés dans la perspective de rendre le tarif moins volatil aux effets du nombre réel de jours d'interruption. Afin que les modifications proposées n'aient pas d'impacts négatifs sur les autres clients, la Régie accepte que le transfert de coûts soit neutralisé à travers l'ajustement des grilles tarifaires de distributions interruptible et continu.

La Régie comprend que ces propositions ne devraient pas, dans le présent cas, créer d'interfinancement entre les services dégroupés d'équilibrage et de distribution. Quant à l'interfinancement entre les catégories de clients à l'intérieur d'un même service, la Régie prend acte de l'engagement du distributeur d'en cibler les déplacements (résultant d'un possible amenuisement du transfert de coûts) et de corriger, le cas échéant la situation. L'importance de cet interfinancement sera mesurée dans la prochaine étude d'allocation du coût de service.

5. PROGRAMME DE PRODUITS FINANCIERS DÉRIVÉS

La preuve de SCGM sur le programme de produits financiers dérivés est présentée sous la cote SCGM-5, document 2. L'annexe 2 présente un résumé des propositions relatives au programme de produits financiers dérivés. SCGM propose de maintenir ce programme. Les outils autorisés ne changent pas. Le prix d'exercice maximal pour l'achat des options est maintenu et celui pour contrats d'échange et plancher des colliers est mis à jour. Des modifications affectent les balises temporelles et volumétriques.

5.1 MODIFICATION AFFECTANT LES BALISES TEMPORELLES

SCGM propose d'utiliser une plus longue période sur laquelle la balise temporelle peut s'appliquer. La balise temporelle actuelle qui est une période roulante de 36 mois est portée à une date fixe qui ne dépassera pas octobre 2008 pour le dossier tarifaire 2005 et octobre 2009 pour le dossier tarifaire 2006 et ainsi de suite[17].

Le passage à une date fixe se justifie, selon SCGM, par la forme de la courbe des prix à terme du gaz naturel. Depuis quelques années, la courbe à terme est inversée, c'est-à-dire que plus l'échéance est lointaine, plus le prix d'achat du gaz naturel est bas[18]. SCGM veut mettre en place, à la suite de l'autorisation de la Régie, des opérations de couverture à long terme à des prix inférieurs à ceux anticipés par le marché à terme pour la prochaine saison gazière[19].

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17 NS, volume 1, page 281, lignes 24 à 27.
18 Pièce SCGM-5, document 1, pages 3 et 4.
19 NS, volume 1, page 281, lignes 12 à 15.

En outre, le marché des produits dérivés sur le gaz naturel fonctionne par saison gazière, soit l'hiver et l'été. Il est plus avantageux de transiger par saison, tant pour la rapidité d'exécution que pour l'obtention de la meilleure cote possible[20].

5.2 MODIFICATIONS AFFECTANT LES BALISES VOLUMÉTRIQUES

Puisque l'utilisation de dérivés financiers par SCGM a comme prémisse de ne pas être spéculative, il est primordial de s'assurer que les volumes protégés dans le temps ne dépasseront jamais les volumes en service de fourniture de gaz naturel.

La méthodologie pour quantifier la limite volumétrique annuelle repose sur des hypothèses de déplacement des volumes en service de fourniture de gaz naturel de SCGM vers les achats directs ou d'autres sources d'énergie (facteur de déplacement) et sur le degré de précision de la prévision des prix des contrats d'échange dans le temps (facteur d'incertitude).

5.2.1 FACTEUR DE DÉPLACEMENT

Depuis le dossier tarifaire 2002[21], SCGM utilise les données historiques de consommation projetées pour établir le facteur de déplacement. SCGM recommande d'utiliser dorénavant les données historiques de consommation réalisées, car elles sont beaucoup moins volatiles[22]. Ces données de consommation réalisées ont également l'avantage de refléter la réelle variation des volumes achetés. De plus, les données de consommation projetées, bien que plus conservatrices, échouent aux tests statistiques de normalité[23].

5.2.2 FACTEUR D'INCERTITUDE

Le facteur d'incertitude fixe le portefeuille cible de protection en fonction du temps. La méthodologie utilisée intègre la relation inverse entre la période de temps et le degré de confiance.

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20 Pièce SCGM-5, document 1, page 3.
21 Dossier R-3463-2001.
22 Pièce SCGM-5, document 1, page 8.
23 *Ibid.*

L'évolution future des prix du gaz naturel est incertaine. En raison d'éléments aléatoires, imprévisibles et souvent exogènes dans le comportement des prix, il y aura systématiquement une différence entre les prix protégés et les prix réellement observés. L'erreur de prévision qui en découle est généralement d'autant plus grande que l'horizon de prévision est loin[24].

Pour la première année, SCGM souhaite protéger par l'utilisation de l'un ou l'autre des outils financiers autorisés, au moins 20 %, mais au maximum 75 % des volumes prévus en service de fourniture de gaz naturel. Ce sont les mêmes valeurs que celles présentées dans le dossier tarifaire 2004. Pour les années subséquentes, SCGM propose d'utiliser successivement un facteur d'incertitude fixe de 75 %[25].

Ce facteur est fixé à 75 % pour des raisons opérationnelles. Sur une base quotidienne, SCGM conserve près de 25 % de ses approvisionnements en achat au comptant et le solde à indice. Fixé à 75 %, le facteur permet de conserver le niveau opérationnel d'achat au comptant, même s'il se produit une forte migration du service de fourniture de gaz naturel vers les achats directs ou les achats à prix fixe[26]. Le facteur d'incertitude proposé se veut simple et plus explicite qu'auparavant.

5.3 LIMITES FINANCIÈRES DES PRIX D'EXERCICE

Prix maximal pour contrat d'échange et plancher de colliers

SCGM recommande de faire passer le prix maximal pour contrats d'échange et plancher de colliers de 6,48 $/GJ à 6,91 $/GJ à AECO dans le but de maintenir une marge de manœuvre suffisante tout en restant compétitive[27].

Avec un prix de 6,91 $/GJ, SCGM démontre que ses tarifs sont compétitifs avec ceux offerts par Hydro-Québec pour plus de 92 % de la clientèle commerciale en service de fourniture. SCGM soumet que pour être compétitive auprès de 100 % de la clientèle commerciale, elle devrait utiliser un prix maximal de 5,80 $/GJ[28]. Au niveau actuel des prix,

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24 Dossier R-3463-2001, pièce SCGM-1, document 3, page 12; dossier R-3510-2003, pièce SCGM-5, document 1, page 11; dossier R-3529-2004, pièce SCGM-5, document 1, page 14.
25 Pièce SCGM-5, document 1, page 14.
26 *Ibid.*
27 *Ibid.* à la page 5.
28 *Ibid.* à la page 17.

cette limite empêcherait toute fixation des prix à l'aide de contrats d'échange pour les hivers 2005 et 2006 et limiterait les transactions sur les années gazières 2006, 2007 et 2008[29].

Prix d'exercice maximal pour les options ou combinaisons d'outils

SCGM recommande que le prix d'exercice maximal soit maintenu à 11 $/GJ, à l'achat. En contexte de prix élevés et de grande volatilité des prix, le prix d'exercice maximal à l'achat de 11 $/GJ demeure approprié[30].

L'utilisation d'options d'achat peut s'avérer un puissant outil de contrôle des prix lorsque le marché subit des chocs sur l'offre. La marge de manœuvre permise par un prix d'exercice maximal pour les options d'achat à 11 $/GJ est donc toujours nécessaire.

5.4 OPINION DE LA RÉGIE

La Régie note que les modifications sont d'ordre technique et n'affectent pas les trois principaux objectifs initiaux du programme de dérivés financiers :

- limiter l'impact des flambées de prix lors de cycles haussiers ou lors de pointes de la demande sur le marché;
- saisir des opportunités de marché pour protéger la position concurrentielle du gaz naturel;
- stabiliser le prix du gaz naturel en réduisant la volatilité du portefeuille.

Sur les modifications aux balises temporelles et volumétriques

La Régie accepte la proposition du distributeur de modifier la balise temporelle. Dans un contexte de courbe des prix à terme inversée, la Régie juge raisonnable d'accorder à SCGM la possibilité de pouvoir transiger sur une période plus longue et ainsi mettre en place des opérations de couverture à long terme à des prix inférieurs à ceux anticipés par le marché pour la prochaine saison gazière.

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29 Pièce SCGM-5, document 1, page 5.
30 *Ibid.* à la page 6.

La Régie accepte les modifications techniques proposées aux facteurs de déplacement et d'incertitude et les limites volumétriques qui en découlent. Les modifications proposées rendent les calculs plus simples. Elles permettent de mieux refléter la réelle variation des volumes achetés et de conserver un niveau d'approvisionnement au comptant pouvant tenir compte d'une migration des clients du service de fourniture de gaz naturel vers les achats directs ou les achats à prix fixe.

Sur les limites financières des prix d'exercice

La Régie accepte la proposition du distributeur de fixer à 6,91 $/GJ à AECO le prix maximal pour les contrats d'échange et plancher de colliers. La Régie accepte également la proposition de reconduire le prix d'exercice maximal pour l'achat des options de moins de un an à 11 $/GJ à AECO. Les explications présentées par SCGM quant aux conditions de marchés très volatiles et quant aux prix très élevés sont justifiées dans le présent contexte gazier.

6. PLAN D'APPROVISIONNEMENT GAZIER – HORIZON 2005-2007

Tel que requis par le *Règlement sur la teneur et la périodicité du plan d'approvisionnement*[31], SCGM dépose son plan d'approvisionnement gazier à la pièce SCGM-4. Ce plan présente la prévision triennale de la demande de gaz ainsi que les outils d'approvisionnement requis pour satisfaire cette demande.

6.1 DEMANDE DE GAZ NATUREL

Hypothèses économiques et situation concurrentielle

SCGM présente deux scénarios de demande : un scénario de base et un scénario favorable.

Le scénario de base repose sur les hypothèses suivantes :

- une croissance économique annuelle soutenue se situant entre 3,1 % et 3,3 %;

[31] (2001) 133 G.O. II, 6037.

- une prévision du prix de la fourniture de gaz provenant de l'Alberta variant entre 5,65 $/GJ et 6,32 $/GJ;
- un prix du mazout n° 6 variant entre 30,87 $ et 32,58 $ CA/baril;
- une augmentation annuelle ajustée au taux d'inflation pour les tarifs d'électricité régulière et l'équivalence entre le tarif régulier et le tarif bi-énergie d'Hydro-Québec à partir d'avril 2006.

En vertu du scénario de base, la position concurrentielle du gaz naturel dans les différents marchés est défavorable par rapport au mazout sur tout l'horizon du plan. La position concurrentielle du gaz naturel par rapport à l'électricité est favorable dans le marché commercial, mais défavorable dans le marché résidentiel.

Le scénario favorable repose sur une situation concurrentielle avantageuse du gaz par rapport au mazout n° 6 ainsi que sur la modification d'autres facteurs affectant à la hausse la demande des clients de la grande entreprise.

Prévision de la demande

Sous le scénario de base les livraisons dans le marché des grandes entreprises diminueront de 10 % (273 $10^6 m^3$) entre 2005 et 2006 en raison du non-renouvellement anticipé du contrat d'un client majeur en service continu. Les livraisons aux clients petit et moyen débits augmenteront d'environ de 2,7 % (80 $10^6 m^3$) par année en raison de la croissance économique soutenue et de l'abrogation au 1er avril 2006 du tarif bi-énergie d'Hydro-Québec. Bien qu'en 2007, les livraisons projetées dans le secteur de la grande entreprise augmentent de près de 41 % (988,3 $10^6 m^3$) à cause de la demande de la nouvelle génération électrique, la demande totale approvisionnée par le distributeur subit une décroissance de 5,4 % entre 2005 et 2007. En effet, la demande créée par la génération électrique n'a pas d'impact sur le plan d'approvisionnement et en est donc exclue. Le distributeur considère que le client fournira son approvisionnement gazier.

SCGM émet l'hypothèse que le prix du service de fourniture de gaz naturel anticipé pour 2005 n'aura pas d'impact négatif sur la demande à cause des mesures prises par le distributeur pour limiter les impacts de la volatilité élevée des prix sur la demande de gaz naturel.

Le tableau 6 présente les prévisions, excluant la génération électrique, anticipées sous les deux scénarios. Ces prévisions tiennent compte des pertes de consommation attribuables aux programmes d'efficacité énergétique.

TABLEAU 6
Demande de gaz naturel 2005-2007
excluant celle de la génération électrique
(avant interruptions) – 10^6 m³

	Scénario de base			Scénario favorable		
	2005	**2006**	**2007**	**2005**	**2006**	**2007**
Service continu	4 816	4 550	4 641	4 816	4 893	4 984
Service interruptible	801	752	672	801	1 233	1 137
Total	5 617	5 302	5 314	5 617	6 126	6 121

Source : Pièce SCGM -4, document 1, pages 19, 23 et 25.

6.2 CONTEXTE ET STRATÉGIES D'APPROVISIONNEMENT

Selon le distributeur, l'objectif premier du plan est de procurer aux clients un approvisionnement sécuritaire tout en s'assurant que le coût d'utilisation du gaz naturel soit le plus bas possible et concurrentiel avec celui des énergies alternatives. Spécifiquement, le distributeur contracte les outils nécessaires afin de rencontrer la demande en pointe et la demande saisonnière des clients en service continu et, dans la mesure du possible, celle des clients interruptibles. Ces approvisionnements doivent être suffisamment flexibles pour faire face aux fluctuations causées par le climat et par l'économie.

6.2.1 FOURNITURE

Le distributeur prévoit évoluer dans un contexte de prix élevé du gaz ainsi que d'une grande volatilité des prix. Sa stratégie d'acquisition de la fourniture varie en fonction du point d'acquisition. À AECO, SCGM sélectionne les fournisseurs en procédant par appel d'offres et limite à des périodes de 12 et 24 mois ses contrats d'achat à indice mensuel. Cette flexibilité permet de réévaluer plus souvent le crédit des fournisseurs.

À Dawn, le distributeur préfère avoir des contrats au moins deux ans à l'avance afin de pouvoir se repositionner à AECO advenant le tarissement de ce marché secondaire. À ce point d'acquisition, les fournisseurs sont sélectionnés par invitation selon les critères suivants : la cote de crédit, la crédibilité et la prime de lieu demandée.

De façon générale, SCGM planifie contracter entre 65 % et 75 % de ses besoins avant le début de l'année gazière et conserver au moins 25 % de ses achats au comptant afin d'être en mesure de réagir aux variations de la demande causées par la migration entre les clients en achats directs et ceux sous le service de fourniture du distributeur, ainsi qu'aux aléas de la température.

6.2.2 TRANSPORT

SCGM poursuit son objectif de minimiser son coût de transport en diminuant la capacité longue distance (FTLH) et en y jumelant des achats à Dawn. Ces achats à Dawn sont transportés sur un contrat de courte distance (FTSH), à des coûts moindres. Le transport provenant du bassin sédimentaire de l'Ouest canadien est presque entièrement utilisé, alors que le transport provenant de Dawn est celui qui s'ajuste à la variation de la demande. Tout comme pour la fourniture, SCGM surveille la valeur du transport sur le marché secondaire afin de se repositionner à AECO advenant le cas où la valeur du marché secondaire annulerait les économies reliées à cette option à Dawn.

Pour l'année 2005, le coefficient d'utilisation anticipé sur les contrats de transport FTLH est de 99,8 %.

6.2.3 ÉQUILIBRAGE

Le portefeuille d'outils d'équilibrage de SCGM est constitué de trois sites d'entreposage souterrain, d'une transaction d'échange de gaz naturel été-hiver et de l'usine de liquéfaction dont SCGM est propriétaire.

Le tableau 7 montre les capacités contractuelles des sites d'entreposage et les capacités requises pour l'année 2005.

TABLEAU 7
Année 2005

Entreposage	Capacités contractuelles (10^3m^3)	Capacités requises (10^3m^3)
Pointe du Lac*	22 592	67 000
Saint-Flavien*	95 487	107 000
Gaz naturel liquide (GNL)	58 591	42 000
Union Gas	597 625	550 000

* Possibilité d'approvisionner ces sites d'entreposage plus d'une fois dans l'année.
Source : Pièces SCGM-3, document 1, page 7 et SCGM-3, document 4.

6.2.4 SOURCES D'APPROVISIONNEMENT ET DEMANDE

Pour l'année 2005, le distributeur anticipe une demande de pointe des clients en service continu pour une température de 44 degrés-jours (DJ) de 30 279 10^3m^3. Afin de répondre à cette demande de pointe, le distributeur a contracté des outils pouvant desservir une consommation de 31 710 10^3m^3. L'écart entre la demande et les outils à la disposition du distributeur correspond à la provision de pointe et représente 4,7 % de la demande totale en pointe.

Le distributeur prévoit interrompre un volume de 56 10^6m^3 durant l'hiver 2005. Ce volume représente 7 % de la demande des clients en service interruptible.

6.3 CARACTÈRE OPTIMAL DE LA STRUCTURE CHOISIE

SCGM mentionne que l'expérience des dernières années lui a démontré que pour faire face à la réalité opérationnelle et commerciale de l'approvisionnement, elle doit dégager du plan une provision de pointe de l'ordre de 3,5 % à 6 %.

Cette marge de manœuvre permet de combler les besoins de pointe des clients en service interruptible du volet 1B pour un volume de 709 10^3m^3 et de faire face aux variations de la consommation découlant des fluctuations de la température et de la demande des clients industriels.

Le distributeur fait valoir qu'il doit se positionner dans le marché nord-américain particulièrement au niveau de l'équilibrage. Il considère que l'entreposage de Union Gas est un actif hautement recherché et qu'il fait partie des outils stratégiques à conserver dans son portefeuille. Cette approche découle de la demande grandissante en gaz naturel pour la génération électrique et de la rareté des sites géologiques d'entreposage.

6.4 OPINION DE LA RÉGIE

La Régie juge que le plan d'approvisionnement couvrant l'horizon 2005 à 2007 est conforme aux exigences du *Règlement sur la teneur et la périodicité du plan d'approvisionnement*. Elle évalue ce plan d'approvisionnement sous les aspects suivants : la sécurité d'approvisionnement et le caractère optimal du plan.

Sur la sécurité d'approvisionnement

La Régie note que le portefeuille d'approvisionnement rencontre les besoins annuels, saisonniers et de pointe de la clientèle.

L'examen de la preuve démontre que, pour les besoins de pointe, les outils à la disposition du distributeur permettent de rencontrer une demande pour une température de 44 DJ. À ce chapitre, la Régie observe qu'au cours des dix dernières années de telles journées ont été très peu fréquentes[32]. La Régie note qu'en ce qui concerne les besoins de pointe pour l'année 2005, le distributeur maintient une provision représentant 4,7 % de la demande de pointe.

La Régie constate que, pour la demande saisonnière en hiver, le volume d'interruption est de 7 % et qu'il est proportionnellement plus faible que celui du dossier tarifaire de l'an dernier qui était de 14 %[33]. De plus, comme l'illustre le tableau 7, elle note que l'entreposage à l'usine de liquéfaction et chez Union Gas n'est pas complètement utilisé.

Dans ces conditions, la Régie juge que le plan d'approvisionnement montre suffisamment de flexibilité pour faire face aux fluctuations de la demande. La Régie est satisfaite des

32 Pièce SCGM-3, document 4.6, pages 2 et 3.
33 Dossier R-3510-2003, pièce SCGM-3, document 4, page 1.

stratégies du distributeur quant à la sécurité d'approvisionnement de la franchise sur l'horizon du plan.

Sur le caractère optimal du plan d'approvisionnement

La Régie doit examiner le plan et en apprécier son optimalité de manière à s'assurer que les tarifs de transport et d'équilibrage qui en découlent soient justes et raisonnables pour l'ensemble des clients. L'exercice requiert d'évaluer et d'apprécier les moyens proposés et leurs coûts. Pour ce faire, la Régie doit pouvoir, à partir de la preuve déposée au dossier, être en mesure de faire cette analyse.

La Régie est satisfaite des explications données en audience concernant l'optimalité du plan. Par ailleurs, la Régie prend note de l'engagement du distributeur d'établir, lors du prochain dossier tarifaire, des paramètres ou des repères qui permettront d'apprécier les marges de manœuvres nécessaires et optimales à la réalisation du plan.

En conclusion, la Régie approuve le plan d'approvisionnement gazier pour l'année 2005.

7. AUTRES SUJETS D'AUDIENCE

7.1 MODIFICATIONS AUX P.R.C. ET P.R.R.C.

PREUVE DE SCGM

L'objectif du programme de rabais à la consommation (P.R.C.) est de réaliser une nouvelle vente de gaz naturel chez un nouveau client ou chez un client existant alors que l'objectif du programme de rétention par voie de rabais à la consommation (P.R.R.C.) est de maintenir la consommation de gaz chez un client existant[34].

L'évolution récente du marché ainsi que le désir de SCGM de poursuivre son développement amène le distributeur à proposer certains ajustements et améliorations à ces programmes[35].

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[34] Pièce SCGM-2, document 10, page 2.
[35] Pièce SCGM-2, document 8, page 1.

Un ajustement important est l'admissibilité aux P.R.C et P.R.R.C. de tous les équipements à gaz naturel. Selon SCGM, l'impact marginal de un mètre cube de gaz consommé est le même peu importe l'appareil ou l'application pour lequel il est utilisé.

Dans le cas du P.R.C. nouvelle construction, cet élargissement permet à SCGM de favoriser, dans le marché résidentiel, l'installation d'un maximum d'appareils périphériques, tels que les foyers, cuisinières, barbecues ou chauffe-piscine.

Avec cet élargissement, la clause exemptant les clients des tarifs de distribution D_1, D_2 et D_M de l'obligation annuelle est maintenue, sauf pour les bénéficiaires de l'aide financière utilisant le gaz naturel majoritairement pour des procédés. Cette exception vise à protéger les investissements du distributeur.

Désormais, le rabais ne s'applique que sur le tarif du service de distribution.

POSITION DE SÉ/AQLPA

S.É/AQLPA émet des réserves quant à l'admissibilité de certains équipements périphériques, tels que les foyers et les barbecues. Les équipements périphériques ayant une efficacité inférieure à 50 % devraient être exclus des dépenses admissibles. Quant aux autres équipements, il y aurait lieu d'énumérer spécifiquement les équipements admissibles après que la Régie aura comparé leur efficacité et leurs émissions atmosphériques à celles des équipements des filières concurrentes[36].

De plus, il devrait être requis que le client installe les accessoires adéquats pour maximiser l'efficacité de ces équipements, tels que des thermostats électroniques programmables ou d'autres équipements de contrôle[37].

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[36] Pièce SÉ/AQLPA-2, document 2, page 12.
[37] *Ibid.* à la page 10.

7.2 PROGRAMME DE FINANCEMENT POUR LA CLIENTÈLE AFFAIRES

PREUVE DE SCGM

Dans sa décision D-2000-188[38], la Régie autorise SCGM à offrir un programme commercial axé sur le financement (PCAF) qui consiste à octroyer un financement correspondant à l'écart entre le coût des équipements ainsi que leur installation et le rabais tarifaire offert au client en vertu des P.R.C. et P.R.R.C. Toutefois, depuis l'implantation de ce programme, SCGM a octroyé uniquement deux prêts à des clients existants[39].

Constatant que le PCAF ne répondait pas aux besoins de sa clientèle, le distributeur a sollicité à l'automne 2002 les services des institutions financières au Québec pour offrir un programme de financement en partenariat avec SCGM[40].

La Banque Scotia et SCGM, en partenariat avec l'entreprise GHR Systems[41] ont développé un concept de traitement des demandes de prêts et d'enquêtes de crédit complètement automatisé et un système informatique pour traiter les demandes de financement dans un délai de 48 heures. De plus, les gestionnaires et les représentants aux ventes de SCGM ont accès au système informatique sur le site Internet de GHR Systems pour vérifier l'avancement des dossiers de crédit[42].

SCGM propose de lancer un nouveau programme de financement pour permettre à ses clients affaires existants et potentiels d'avoir accès, rapidement et de façon simple et directe, à du financement d'équipement et de matériel de chauffage ainsi que de procédés à gaz naturel. Ce nouveau programme sera utilisé et promu par les représentants et les partenaires certifiés de SCGM[43].

La clientèle visée par ce programme est celle des marchés multilocatif, commercial et industriel aux tarifs 1, 3 et M excluant les entreprises en démarrage (moins de 24 mois d'existence) et le secteur de la restauration. Le programme de financement est destiné aux propriétaires de petites entreprises dont le chiffre d'affaires est inférieur à environ 5 M$ et il

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38 Dossier R-3447-2000, 23 octobre 2000.
39 Pièce SCGM-2, document 7, page 3.
40 *Ibid.* à la page 5.
41 GHR Systems est le fournisseur de systèmes informatiques et service spécialisés dans le financement.
42 Pièce SCGM-2, document 7, page 9.
43 *Ibid.* à la page 8.

vise à financer des montants entre 5 000 $ et 50 000 $ servant à l'achat et à l'installation d'appareils à gaz naturel[44].

Selon l'entente entre SCGM et la Banque Scotia, cette dernière sera responsable de traiter les demandes de financement à partir du moment où elle reçoit une demande de crédit, et ce, jusqu'à l'échéance du prêt. Le taux d'intérêt sera établi par la Banque Scotia et sera révisé trimestriellement[45].

De son côté, SCGM est responsable de promouvoir le programme de financement auprès de sa clientèle et de compléter la confirmation d'identification du client lorsque ce dernier désire faire une demande de crédit pour financer son installation[46].

Selon l'entente négociée avec SCGM, la Banque Scotia assume les frais reliés à l'élaboration et à la mise en place du programme ainsi que les frais d'administration y incluant le coût de la gestion des prêts, de l'administration du programme de même que les frais d'étude et d'évaluation des dossiers de crédit[47].

En contrepartie, SCGM s'engage à contribuer au coût du programme de manière à compenser la Banque Scotia pour une proportion des pertes de crédit, le montant étant limité à 220 000 $ pour les deux premières années. Deux ans après le lancement du programme, un nouveau plafond sera fixé par le Comité de direction pour les années subséquentes en vue d'assurer que ce plafond reflète adéquatement la proportion du coût du programme par rapport aux ventes effectuées. Par ailleurs, SCGM désire imputer les coûts du programme de financement à son coût de service[48].

En raison de l'application limitée du programme, SCGM souhaite que le PCAF demeure disponible, et ce, tant et aussi longtemps qu'une alternative n'aura pas été mise au point et qu'elle ne satisfera pas l'ensemble de la clientèle visée par le PCAF[49].

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44 Pièce SCGM-2, document 7, page 8.
45 *Ibid.* aux pages 8 et 9.
46 *Ibid.* à la page 9.
47 *Ibid.* à la page 12.
48 *Ibid.*
49 *Ibid.* à la page 8.

POSITION DE LA FCEI

La FCEI soumet que les critères d'admissibilité au programme développé en partenariat avec la Banque Scotia devraient être modifiés afin d'offrir ce service à l'ensemble de la clientèle, et ce, en incluant les entreprises en démarrage et les entreprises du secteur de la restauration[50].

La FCEI souligne les difficultés de financement croissantes des petites et moyennes entreprises auprès des institutions financières. L'intervenante est d'avis que tous les clients d'une même classe tarifaire devraient avoir accès aux mêmes services, d'autant plus si ces derniers en supportent les coûts. La FCEI prétend que SCGM devrait se satisfaire de l'évaluation de crédit effectuée par l'institution financière comme critère d'acceptation sans discrimination quant au type de marché de sa clientèle[51].

7.3 PROGRAMMES DE FLEXIBILITÉ TARIFAIRE MAZOUT ET BI-ÉNERGIE

SCGM demande à la Régie de reconduire, pour une période de deux ans se terminant le 30 septembre 2006, les programmes de flexibilité tarifaire mazout et bi-énergie pour les tarifs 1, 3 et M. Depuis leur instauration, ces programmes ont permis de prévenir une perte de volumes et de revenus transport, équilibrage et distribution ainsi que la hausse tarifaire qui en résulterait auprès de l'ensemble de la clientèle[52].

7.4 OPINION DE LA RÉGIE

Sur les P.R.C. et P.R.R.C.

Les modifications proposées aux P.R.C. et P.R.R.C. visent à apporter des précisions, à enlever des irritants ainsi qu'à éliminer certaines incohérences.

50 Pièce FCEI -1, page 6.
51 *Ibid.* à la page 5.
52 Pièce SCGM -2, document 1, pages 2 et 3.

La Régie ne juge pas opportun, dans le cas présent, d'exiger que tous les équipements admissibles aux P.R.C. et P.R.R.C. rencontrent les normes maximales d'efficacité énergétique. La Régie réitère qu'elle considère inapproprié d'imposer des conditions quant au choix des équipements admissibles au programme. Elle juge préférable que le client garde le libre choix des équipements qu'il désire installer. En outre, de telles conditions risquent de rendre plus difficile l'atteinte des résultats du programme[53].

La Régie juge que les équipements périphériques ne doivent pas être admissibles aux programmes en cause. Bien que la Régie soit sensible aux considérations « marketing » mises de l'avant par le distributeur, elle est toutefois d'avis qu'elle ne peut pas, étant donné la nature des équipements considérés, faire supporter les subventions éventuelles par la communauté des usagers.

Sur le programme de financement pour la clientèle affaires

La Régie note que le nouveau programme de financement pour la clientèle affaires a le même objectif que celui approuvé par la décision D-2000-188. Il s'en distingue notamment par le recours à une tierce partie pour la gestion du financement et l'exclusion des entreprises en démarrage ainsi que celles du secteur de la restauration. L'exclusion a été assimilée à une certaine forme de discrimination.

Lorsqu'un motif de discrimination est soulevé, la Régie doit d'abord vérifier s'il y a effectivement un traitement discriminatoire envers certains usagers. Dans l'affirmative, la Régie doit examiner, à la lumière des faits connus au dossier, si cette discrimination est indue.

L'exclusion explicite prévue pour un certain type de clientèle amène la Régie à conclure que le programme de financement pour la clientèle affaires est, à sa face même, discriminatoire puisqu'il accorde un traitement différent à certains clients à l'intérieur des mêmes catégories tarifaires.

D'une part, la Régie constate que l'exclusion de ces segments de marché relève d'une exigence de l'institution financière pour se conformer aux besoins spécifiés par SCGM dans son appel d'offres. Selon la compréhension de la Régie, l'institution financière est prête à offrir un taux de financement fixe compétitif et à respecter les conditions de l'appel d'offres

[53] Décision D-2000-188, R-3447-2000, 23 octobre 2000.

en autant que les segments de marché qu'elle juge plus à risque soient, dans un premier temps, exclus[54].

D'autre part, la Régie constate que l'exclusion des entreprises en démarrage et du secteur de la restauration pourrait n'être que temporaire. SCGM est consciente du problème causé par ce type de discrimination et elle entend le régler dès l'automne 2005[55].

Entre temps, compte tenu de l'application limitée du nouveau programme proposé, SCGM conserve le PCAF dans sa forme actuelle. Cette solution temporaire sera en vigueur tant et aussi longtemps qu'une alternative n'aura pas été mise en place pour satisfaire l'ensemble de la clientèle visée par le PCAF[56].

Dans ces circonstances, la Régie juge que l'exclusion des entreprises en démarrage et celles du secteur de la restauration ne constitue pas une discrimination indue. Toutefois, SCGM devra présenter, dans le cadre du prochain dossier tarifaire, le résultat de ses travaux et la solution envisagée pour desservir les entreprises en démarrage et celles du secteur de la restauration.

Sur les programmes de flexibilité tarifaire mazout et bi-énergie

La Régie accepte de reconduire pour deux ans le programme de flexibilité tarifaire mazout. Quant au programme de flexibilité tarifaire bi-énergie gaz-électricité, la Régie rappelle que, conformément à la décision D-96-24[57] de la Régie du gaz naturel, le distributeur doit mettre fin à ce programme si le programme bi-énergie d'Hydro-Québec se termine.

Par conséquent, la Régie maintient, jusqu'au 30 septembre 2005, tel que décidé dans la décision D-2003-180, le programme de flexibilité tarifaire gaz-électricité et demande à SCGM de lui démontrer, lors du prochain dossier tarifaire, la pertinence de maintenir le programme de flexibilité tarifaire bi-énergie gaz-électricité, étant donné la récente décision D-2004-170 de la Régie dans le dossier R-3531-2004.

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54 NS, volume 1, page 99.
55 Pièce SCGM-7, document 7.9, réponse 2b.
56 Pièce SCGM-2, document 7, page 8.
57 Décision D-96-24, dossier R-3351-96, 5 juillet 1996.

8. RAPPORTS SPÉCIFIQUES DEMANDÉS PAR LA RÉGIE ET SUIVI DE DÉCISIONS

8.1 PGEÉ

SCGM présente des rapports de suivis pour le PGEÉ. Ces rapports comparent les résultats du PGEÉ aux prévisions, pour la période de six mois se terminant le 31 mars 2004. Au cours de cette période, SCGM a réalisé 52 % des économies envisagées, pour un total de 3,5 Mm^3, a rejoint 47 % des participants prévus et a dépensé 91 % du budget anticipé[58].

Plan 2004-2007

Le coût direct du PGEÉ sur l'horizon 2004-2007 est estimé à 16,5 M$, dont 12,3 M$ pour l'aide financière directe et 4,2 M$ pour les dépenses d'exploitation.

SCGM prévoit des économies cumulatives de près de 422,7 Mm^3 sur la durée de vie utile des mesures implantées, générant des économies nettes de 160,4 M$ (en dollars de 2004) pour les participants, comparativement à 154,1 M$ pour le PGEÉ 2003-2006. L'application du test du coût total en ressources indique des économies nettes de 63,9 M$, comparativement à 73,3 M$ pour le PGEÉ 2003-2006.

Pour l'année 2004-2005, SCGM demande à la Régie l'approbation d'un budget de 5,1 M$, dont 3,7 M$ d'aide financière et 1,4 M$ de dépenses d'exploitation. La prévision initiale du PGEÉ 2003-2006 pour l'année 2004-2005 correspondait, à peu de chose près, au même montant[59].

Pour la première année d'implantation du PGEÉ 2004-2007, SCGM envisage des économies annuelles de 10,6 Mm^3, générant pour les participants des économies monétaires nettes de 51,6 M$ sur la durée de vie utile des programmes. SCGM prévoit des pertes de revenus de 0,7 M$ et estime à 1,332 % l'impact tarifaire du PGEÉ, basé sur des revenus de distribution de 436,96 M$[60].

58 Pièce SCGM-9, document 1, page 25; pièce SCGM-9, document 2, page 2.
59 Pièce SCGM-9, document 1, page 4.
60 *Ibid.* aux pages 4, 65 et 67.

À cet égard, SCGM précise qu'aucun plafond n'est établi, *a priori*, en matière d'impact tarifaire et que ce dernier est fixé annuellement, en fonction des besoins. SCGM demeure néanmoins préoccupée par l'évolution de ses tarifs dans son appréciation des exigences en matière d'efficacité énergétique[61].

Le PGEÉ 2004-2007 comporte quinze programmes dont trois ne génèrent aucune économie d'énergie comptabilisée. Ces trois programmes, dits intangibles, visent la sensibilisation de tous les marchés à l'efficacité énergétique. SCGM offre cinq programmes tangibles pour le marché résidentiel et sept pour le marché commercial, institutionnel et industriel (CII), incluant les clients de la grande entreprise et les clients des immeubles multilocatifs[62].

SCGM met à jour le portefeuille du PGEÉ 2004-2007. Ce PGEÉ diffère du plan de l'année précédente sous quatre aspects[63] :

- pour le marché résidentiel, SCGM retire le programme de la trousse énergétique (PE 110), en raison d'une transformation du marché[64];
- le taux d'opportunisme appliqué aux programmes destinés à la clientèle de la grande entreprise (VGE) passe à 50 %, conformément à la décision D-2003-180. SCGM compte étudier, au cours de la prochaine année, la possibilité de réduire ce taux d'opportunisme en adaptant ou en modifiant ces programmes[65];
- l'incitatif à la performance est aboli, conformément à la décision D-2004-51[66];
- quatre programmes du PGEÉ sont transférés au FEÉ : le programme communautaire (PE 104), le programme de rénovation pour les habitations unifamiliales (PE 108) et pour les duplex et triplex (PE 112), ainsi que le programme d'enveloppe du bâtiment pour le marché de la nouvelle construction (PE 206).

SCGM présente l'état d'avancement de l'évaluation des programmes du PGEÉ[67]. Elle mentionne être consciente d'un retard quant à l'évaluation de certains programmes et reporte à un dossier ultérieur le dépôt de certains éléments de cette évaluation[68].

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61 NS, volume 1, page 34.
62 Pièce SCGM-9, document 1, page 28.
63 *Ibid.* aux pages 4, 5 et 25 à 59.
64 *Ibid.* aux pages 41 à 43.
65 *Ibid.* à la page 18.
66 Décision D-2004-51, dossier R-3494-2002, 3 mars 2004; pièce SCGM-9, document 1, pages 66 et 67.
67 Pièce SCGM-9, document 1, pages 11 et 12.
68 NS, volume 1, page 29.

SCGM poursuit l'évaluation des taux d'attraction et de fidélisation de la clientèle. Cependant, les recherches de SCGM à ce sujet se soldent « *par un néant absolu. Les seules études portant sur l'effet de fidélisation s'adressent à la rétention d'équipements promus par un programme donné, mais rien sur la clientèle* ». Toutefois, SCGM compte intégrer dans ses exercices d'évaluations futures des questions sur la rétention auprès de la clientèle existante et sur l'attraction auprès de ses nouveaux clients participants à un programme du PGEÉ[69].

Transfert de programmes du PGEÉ au FEÉ

Lors de leur planification triennale respective, les représentants du PGEÉ et du FEÉ se sont consultés afin d'éviter le dédoublement d'efforts et le chevauchement de programmes.

Les parties ont convenu que le PGEÉ concentrera ses activités sur l'implantation de mesures liées aux appareils et systèmes connexes alimentés par le gaz naturel. Le FEÉ se concentrera sur les mesures touchant l'enveloppe du bâtiment et les nouvelles technologies autres que celles alimentées au gaz naturel. Le FEÉ favorisera également les interventions à caractères communautaire ou social. Ainsi, quatre programmes du PGEÉ sont transférés au FEÉ. Le transfert de ces quatre programmes ne réduit aucunement les efforts de SCGM en matière d'efficacité énergétique, puisque la réduction budgétaire d'environ 310 000 $ résultant de ce transfert a été réallouée aux programmes et activités du présent PGEÉ[70].

8.2 FEÉ

Le rapport d'étape 2003-2004 du FEÉ fait état des résultats obtenus et des coûts réels des programmes offerts[71]. En date du 20 juillet 2004, environ 49 % du budget prévu est engagé[72].

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69 Pièce SCGM-9, document 1, pages 18 et 19.
70 *Ibid.* aux pages 28 et 29.
71 Pièce SCGM-9, document 7.
72 Pièce SCGM-9, document 11.

Plan d'action 2004-2005

Le Plan d'action 2004-2005 Horizon 2007 du FEÉ propose des investissements de près de 3,2 M$ pour la mise en oeuvre de 20 programmes devant générer des économies annuelles de l'ordre de 6,8 Mm^3 de gaz naturel au cours de la période du 1er octobre 2004 au 30 septembre 2005[73]. Le Comité de gestion du FEÉ est confiant que ce budget de 3,2 M$ est réaliste, compte tenu de l'expérience vécue et des modifications apportées à l'offre financière des programmes[74].

Pour la clientèle résidentielle, quatre des quatorze programmes proposés visent spécifiquement la clientèle à faible revenu et deux programmes s'adressent au milieu sociocommunautaire[75]. Ces programmes d'aide technique ou financière visent la construction ou la rénovation résidentielle, l'analyse énergétique des bâtiments, l'intervention communautaire, l'installation de panneaux réflecteurs de chaleur ou de murs solaires, la récupération de la chaleur des eaux grises et l'achat de fenêtres certifiées Energy Star.

La clientèle CII bénéficie de six programmes de subvention et de financement portant sur la construction ou la rénovation de bâtiments, l'installation de panneaux réflecteurs de chaleur, de systèmes solaires ou de systèmes récupérateurs de chaleur des eaux grises ainsi que sur la végétalisation des toits en milieu urbain.

Le Plan d'action 2004-2005 prévoit aussi des investissements de 200 000 $ pour effectuer une veille technologique ainsi que des frais de 500 000 $ pour la gestion et la commercialisation du FEÉ. Ces montants sont inclus au budget total proposé. Le coût unitaire des économies d'énergie se chiffre à 0,46 $\$/m^3$[76].

Plan d'action triennal

Pour donner suite à une demande de la Régie, le Comité de gestion du FEÉ dépose une planification sur trois ans de ses activités.

[73] Pièce SCGM-9, document 8, page 4.
[74] NS, volume 1, page 213.
[75] Pièce SCGM-9, document 8, page 4.
[76] *Ibid.*

Le Plan d'action 2004-2005 Horizon 2007 du FEÉ propose 20 programmes axés sur l'enveloppe du bâtiment, l'implantation d'une technologie émergente ou l'expérimentation d'une nouvelle approche commerciale. À l'horizon 2007, ce Plan d'action propose des investissements d'un peu plus de 11 M$[77], dont environ 33 % sont consacrés à la clientèle résidentielle et 67 % à la clientèle CII[78]. Les économies annuelles associées à ces investissements totaux s'élèvent à plus de 26,6 Mm^3 [79].

Tel que décrit à la section 8.1, quatre programmes du PGEÉ ont été transférés au FEÉ. Par ailleurs, un appel de propositions sera lancé afin de solliciter des projets novateurs.

8.3 CASEP

Le mécanisme incitatif maintient le compte d'aide à la substitution d'énergies plus polluantes (CASEP). Le mécanisme incitatif prévoit qu'une somme annuelle de 1 M$ est versée dans un compte pour réaliser des conversions de formes d'énergies plus polluantes vers le gaz naturel.

En 2002-2003, le volume équivalent d'énergie déplacée était de 10,4 Mm^3 et il s'agissait principalement de mazout n° 2[80]. Cependant, le volume équivalent d'énergie déplacée pour l'année à venir n'a pas été estimé par SCGM, puisque le potentiel de déplacement « *est plus grand que les sommes* […] *qui seraient disponibles* »[81].

8.4 OPINION DE LA RÉGIE

Sur le PGEÉ

La Régie constate que les rapports de suivi du PGEÉ respectent les orientations des décisions précédentes en termes de type de données et de qualité de l'information fournis. De plus, les coûts réels du PGEÉ sont conformes aux budgets présentés antérieurement et les frais d'administration sont maintenus à un niveau raisonnable.

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77 Pièce SCGM-9, document 8, page 4.
78 *Ibid.* à la page 11.
79 *Ibid.* à la page 4.
80 Pièce SCGM-9, document 6, page 1.
81 NS, volume 1, pages 35 et 37.

La Régie prend acte de la mise à jour du portefeuille et des modalités des programmes du PGEÉ. La Régie autorise, par ailleurs, le retrait du programme de la trousse énergétique (PE 110), compte tenu des arguments présentés par SCGM.

La Régie prend acte du transfert de quatre programmes du PGEÉ au FEÉ. Elle encourage la concertation entre le Comité de gestion du FEÉ et les représentants de SCGM, en autant que cet arrimage n'affecte ni la mission du FEÉ, ni l'ampleur des efforts déployés par SCGM en efficacité énergétique.

La Régie approuve la mise en oeuvre du PGEÉ 2004-2007 et autorise le budget demandé de 5,1 M$. Par ailleurs, la Régie rappelle à SCGM l'importance de déployer les efforts pour se doter des outils nécessaires à l'évaluation de ses programmes selon les échéances fixées.

La Régie partage les préoccupations de SCGM en ce qui a trait à l'évolution de ses tarifs et réitère son inquiétude quant à l'impact grandissant du PGEÉ sur ces derniers. Bien que la Régie ne remette pas en question le principe général du mécanisme d'ajustement de pertes nettes des revenus (MAPR), elle demande à SCGM, lors du dépôt du prochain dossier tarifaire, de lui proposer une méthode d'établissement du niveau de l'impact tarifaire du PGEÉ, notamment en tenant compte d'un plafonnement des sommes incluses au MAPR ou en reconsidérant certaines modalités.

Sur le FEÉ

La Régie observe, cette année, un effort de concertation et de planification des activités du FEÉ et constate que la période de rodage des activités du FEÉ semble complétée. La Régie autorise le budget de 3,2 M$ demandé pour le FEÉ 2004-2005 Horizon 2007. Les représentants du FEÉ devront expliquer tout écart majeur entre les résultats projetés et obtenus.

La Régie demande aux représentants du FEÉ de poursuivre les efforts de planification pluriannuelle de leurs activités et d'en prévoir le dépôt pour le prochain dossier tarifaire.

Sur le CASEP

La Régie est préoccupée par le fait qu'il n'y ait pas d'objectif mesurable associé au CASEP, d'autant plus que le budget maximal est déjà fixé à 1 M$.

La fixation d'objectifs, en termes d'énergie déplacée et de projets réalisés, permet à la Régie de s'assurer que les montants sont adéquatement alloués. La Régie demande à SCGM, d'inclure ces objectifs annuels au prochain dossier tarifaire, en plus de présenter le détail des projets réalisés pour l'année en cours.

VU ce qui précède;

CONSIDÉRANT la *Loi sur la Régie de l'énergie*[82];

CONSIDÉRANT le *Règlement sur la procédure de la Régie de l'énergie*[83];

La Régie de l'énergie :

RECONDUIT jusqu'au 30 septembre 2006 le programme de flexibilité tarifaire mazout pour les clients des tarifs D_1, D_3 et D_M;

MAINTIENT la reconduction du programme de flexibilité tarifaire bi-énergie jusqu'au 30 septembre 2005, conformément à la décision D-2003-180;

APPROUVE, à compter du 1er octobre 2004, les modifications proposées à certaines conditions d'applications des programmes de rabais à la consommation et de rétention par voie de rabais à la consommation (P.R.C. et P.R.R.C), sauf en ce qui a trait à l'admissibilité des équipements périphériques;

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82 L.R.Q., c. R-6.01.
83 (1998) 130 G.O. II, 1245.

APPROUVE, à compter du 1er octobre 2004, le programme additionnel alternatif à l'actuel programme commercial axé sur le financement (PCAF), tel que décrit à la pièce SCGM-2, document 7;

APPROUVE le plan d'approvisionnement de SCGM pour l'exercice 2005, tel que décrit à la pièce SCGM-4, document 1;

APPROUVE, pour l'exercice financier 2005, les modifications proposées au programme de produits financiers dérivés, les volumes totaux pouvant être protégés en vertu de ce programme ainsi que le plafond applicable aux contrats d'échange à prix fixes;

APPROUVE l'application à l'exercice 2005 du mécanisme incitatif à l'amélioration à la performance approuvé par la Régie dans sa décision D-2004-51;

APPROUVE la mise en œuvre du PGEÉ 2004-2005 et **AUTORISE** le budget de 5,1 M$ prévu à cette fin;

AUTORISE l'utilisation d'une somme de 3 169 883 $ dans la mise en œuvre du Plan d'action 2004-2005 du FEÉ;

AUTORISE le coût en capital moyen de 9,01 % (après partage des gains de productivité) sur la base de tarification pour l'exercice financier 2005;

AUTORISE, dans l'évaluation des projets d'investissements prévus par SCGM pour l'exercice financier 2005, le coût en capital prospectif de 7,04 %;

APPROUVE les modifications aux structures tarifaires décrites à la pièce SCGM-11, document 2;

MODIFIE, à compter du 1er octobre 2004, les tarifs de SCGM de façon à ce qu'ils génèrent les revenus requis totalisant 794 125 000 $, afin de permettre à SCGM de récupérer l'ensemble de ses coûts pour assumer ses services;

AUTORISE la répartition tarifaire proposée à la pièce SCGM-12, document 6;

APPROUVE le texte des tarifs proposé à la pièce SCGM-13, document 1.

Jean-Noël Vallière
Régisseur

Anita Côté-Verhaaf
Régisseure

Francine Roy
Régisseure

Représentants :

- Société en commandite Gaz Métro (SCGM) représentée par M^{e} Jocelyn B. Allard;
- Association des consommateurs industriels de gaz (ACIG) représentée par M^{e} Nicolas Plourde;
- Fédération canadienne de l'entreprise indépendante (FCEI) représentée par M^{e} Liam Turner;
- Groupe de recherche appliquée en macroécologie (GRAME) représenté par M^{me} Isabelle Mime;
- Hydro-Québec représentée par M^{e} Éric Fraser;
- Option consommateurs (OC) représentée par M^{e} Stéphanie Lussier;
- Regroupement national des Conseils régionaux de l'environnement du Québec (RNCREQ) représenté par M. Jean Lacroix;
- Regroupement des organismes environnementaux en énergie (ROEÉ) représenté par M^{e} Eve-Lyne H. Fecteau;
- Stratégies énergétiques et Association québécoise de lutte contre la pollution atmosphérique (SÉ/AQLPA) représenté par M^{e} Dominique Neuman;
- TransCanada Energy Ltd représenté par M^{e} Pierre Tourigny;
- Union des consommateurs (UC) représentée par M^{me} Élisabeth Gibeau;
- Union des municipalités du Québec (UMQ) représentée par M^{e} Steve Cadrin;
- M^{e} Jean-François Ouimette pour la Régie de l'énergie.

ANNEXE 1

MODIFICATIONS AUX STRUCTURES TARIFAIRES

Annexe 1(10 pages)

J.-N. V. _______

A. C.-V. _______

F. R. _______

ANNEXE 1

MODIFICATIONS AUX STRUCTURES TARIFAIRES

SCGM propose certaines modifications aux structures tarifaires. Plus spécifiquement les sujets abordés sont les suivants :

- ajustements reliés aux inventaires;
- service de fourniture – service fourni par le client;
- service d'équilibrage;
- services de distribution D_1 et D_M;
- structure tarifaire et efficacité énergétique;
- texte des tarifs.

1. AJUSTEMENTS RELIÉS AUX INVENTAIRES

Le client qui utilise les services de fourniture, gaz de compression ou de transport de SCGM se voit facturer des ajustements pour tenir compte de la variation de la valeur des inventaires résultant d'un changement dans le prix de ces services ainsi que les coûts reliés au maintien de ces inventaires.

Lors du calcul de ces ajustements, tout inventaire négatif est ramené à une valeur minimale de zéro. SCGM propose d'enlever ce plancher minimal au calcul de l'inventaire de sorte que sa valeur puisse être négative.

Les clients sans inventaires, ceux qui font leur pointe de consommation en été ou qui ont un profil uniforme, ne contribuent pas aux coûts reliés aux inventaires. Sans les clients saisonniers d'été, le distributeur devrait constituer des inventaires supérieurs pour desservir les clients à profil « chauffage », augmentant par le fait même les coûts financiers de maintien des inventaires.

Cette proposition permet de reconnaître le bénéfice du profil de consommation estival au niveau de l'inventaire de SCGM. En fixant à zéro la valeur minimale des inventaires, l'économie ainsi créée par ces clients est répartie à l'ensemble des clients responsables des coûts d'inventaires et non à ceux qui permettent une économie.

La modification proposée accorde un crédit aux clients qui contribuent à réduire les niveaux d'inventaires, au même titre que ces clients se voient accorder un crédit au tarif d'équilibrage. Elle ne change pas les fondements de la méthode de calcul des inventaires.

Les clients des tarifs autres que D_1 se verront toujours facturer des ajustements reliés aux inventaires calculés client par client selon le profil de consommation, avec toutefois la possibilité que l'inventaire soit négatif. Dans le cas des clients du tarif D_1, le bénéfice apporté par le profil avantageux des clients saisonniers est alloué à l'ensemble des clients de ce tarif.

1.1 IMPACT DE LA PROPOSITION SUR LA CLIENTÈLE

Globalement, les revenus générés pour le distributeur par les ajustements reliés aux inventaires ne changent pas avec la modification proposée. Ils seront simplement répartis de façon différente entre les utilisateurs des services.

Sur la base du budget 2003-2004, les clients du service général (tarif D_1) subiront une augmentation globale de 367 000 $ puisque les inventaires sont principalement constitués pour les desservir. Sur une base globale, les clients des tarifs de distribution D_M et D_5 auront droit à une diminution des ajustements facturés; leur consommation moyenne en été est quelquefois supérieure à leur consommation moyenne en hiver. Les clients des services à débit stable (tarifs D_3 et D_4) seront peu affectés globalement.

2. SERVICE DE FOURNITURE – SERVICE FOURNI PAR LE CLIENT

2.1 DÉSÉQUILIBRES VOLUMÉTRIQUES QUOTIDIENS

Règlement financier d'un excédent de livraison relativement à un contrat de « gaz d'appoint pour éviter une interruption. »

Les clients interruptibles, qui ne peuvent ou ne veulent pas s'interrompre, contractent, dans la mesure du possible, du « gaz d'appoint pour éviter une interruption », plutôt que de consommer en retrait interdit.

Aucun service d'équilibrage n'est offert avec un contrat de « gaz d'appoint pour éviter une interruption ». Il en découle que les clients en « gaz d'appoint pour éviter une interruption » doivent s'engager à livrer au distributeur, au cours de la journée prévue d'interruption, un volume [volume journalier contractuel (VJC)] égal à leur consommation de la même journée.

Si la consommation de la journée prévue d'interruption diffère du VJC convenu, les règles relatives au déséquilibre volumétrique quotidien s'appliquent. Pour les fins du calcul du déséquilibre volumétrique quotidien, le VJC du client sera égal à sa consommation de la journée prévue d'interruption. Un déséquilibre volumétrique quotidien se mesure en comparant le volume effectivement livré au VJC.

Certains clients, incapables de gérer leur consommation de manière aussi précise, préfèrent livrer davantage de gaz, plutôt que de se retrouver en situation de retrait interdit. Ce faisant, ils se retrouvent en situation de déséquilibre volumétrique quotidien (excédent de livraison).

Selon les règles en vigueur, SCGM rachète l'excédent de livraison, dans la majorité des cas, à un prix inférieur au prix du marché payé initialement par le client. Pour ce dernier, la solution idéale serait de se voir racheter le gaz naturel et le transport au prix du marché. Cette solution n'est pas acceptable pour SCGM, car elle ne permet pas de maintenir le principe de base de garder indemnes les clients desservis par le distributeur.

Il est proposé que les excédents quotidiens de livraison d'un contrat de « gaz d'appoint pour éviter une interruption », sous la clause de déséquilibre volumétrique quotidien, soient reportés au contrat régulier de fourniture. Les déficiences de livraison demeureront assujetties au règlement financier, tel que prévu au texte des tarifs. En ce qui concerne le service de transport, le déséquilibre volumétrique, excédent et déficience, demeurera réglé financièrement, conformément au texte des tarifs. Cette solution n'a pas d'impact négatif pour les clients desservis par le distributeur, lorsque comparée à la situation actuelle.

Il ne s'agit pas d'une option offerte au client. Le report de l'excédent sera appliqué automatiquement, sauf pour des clients utilisant le service de fourniture du distributeur. Ces derniers, n'ayant pas de contrat de fourniture, devront nécessairement régler financièrement les excédents de livraison, au même titre que les déficiences.

2.2 DÉSÉQUILIBRES VOLUMÉTRIQUES DE LA PÉRIODE CONTRACTUELLE

Un déséquilibre de la période contractuelle survient lorsque le client retire, au cours d'une période contractuelle, un volume de gaz naturel différent de celui qu'il s'est engagé à livrer.

Depuis le dégroupement des services, la procédure de report à la période subséquente des déséquilibres de la période contractuelle a été abolie et le règlement financier à la fin de la période contractuelle est actuellement appliqué.

SCGM propose de permettre aux clients, dont les contrats de fourniture prennent effet à partir du 1er octobre 2004, de choisir entre le règlement financier en fin de période contractuelle ou le report du déséquilibre volumétrique à la période contractuelle selon les modalités suivantes :

- le choix devra être fait et signifié à SCGM avant le début de la période contractuelle du contrat de fourniture;
- par défaut le règlement financier sera appliqué;
- le report sera limité à 5 % des volumes retirés au cours de la période contractuelle et le solde sera réglé financièrement selon les modalités prévues au texte des tarifs;
- le report sera étalé sur une période de 12 mois.

De plus, SCGM pourra exiger le règlement financier dans le cas où le client est jugé financièrement à risque.

Les modalités retenues s'appuient sur les motifs qui suivent :

- l'obligation de faire un choix au début du contrat de fourniture reflète le mode administratif choisi par le client qui fournit son propre service et non la valeur économique qui y serait rattachée, celle-ci étant imprévisible 12 mois à l'avance;
- la limite de 5% des volumes retirés permet de contenir l'importance du financement supporté par les clients qui sont desservis par le distributeur;
- l'étalement du report sur une période de 12 mois entraîne moins d'impacts sur le tarif d'équilibrage ainsi que sur la politique de produits dérivés[84].

3 SERVICE D'ÉQUILIBRAGE

Afin de neutraliser l'effet de la fluctuation du prix d'équilibrage à cause de la différence entre le nombre réel de jours d'interruption et la prévision communiquée aux clients interruptibles, SCGM propose, qu'au 1er octobre de chaque année, un prix d'équilibrage pour chaque client des tarifs de distribution D_3, D_4, D_5 et D_M soit évalué. Ce prix tiendra compte de la consommation réelle des 12 derniers mois, corrigée, le cas échéant, pour refléter le nombre maximum de jours d'interruption prévu au texte des tarifs, selon le sous-tarif et le volet applicables au client interruptible. Ce prix sera facturé pour les 12 mois subséquents.

[84] Pièce SCGM-11, document 2.7.

Le tarif est simplifié étant donné la détermination du taux en début d'année. Actuellement, les 12 derniers mois de consommation servent à établir, chaque mois, le prix du service d'équilibrage. Ce dernier demeurera établi selon la formule actuelle du tarif d'équilibrage incluant la transposition des volumes. Toutefois, pour les clients interruptibles, les paramètres A et H seraient modifiés de façon à considérer un nombre de jours d'interruption égal au nombre maximal indiqué au texte des tarifs[85].

La méthode revient à constater le service d'équilibrage fourni au cours de l'année financière qui se termine et d'assumer que le service à fournir lors de la prochaine année sera similaire. Cette hypothèse est, de façon générale, plausible. Par contre, certains profils de consommation et de livraison peuvent résulter en des prix d'équilibrage plus particuliers.

Pour éviter des cas extrêmes, SCGM propose de fixer un prix minimum et un prix maximum pour le service d'équilibrage. Le prix minimum correspond au prix de l'entreposage fonctionnalisé sous l'espace divisé par 365. Le prix maximal est égal à l'écart de prix entre « D_1 & É au tarif D_1 » et « D_M à réduction maximale » pour le client moyen du tarif D_M.

Les prix minimum et maximum seront évalués en fonction des données du dossier tarifaire sous considération et révisés annuellement.

Selon le distributeur, en plus de simplifier le tarifs, la proposition a l'avantage de stabiliser le taux durant l'année, de rendre les coûts prévisibles pour les clients et de maintenir le principe d'utilisateur payeur chez les clients.

3.1 IMPACT FINANCIER DE LA PROPOSITION

Les modifications au tarif d'équilibrage affecteront directement l'interfinancement observé sous ce service, considérant que les méthodes d'allocation des coûts d'équilibrage ne sont pas modifiées pour l'instant.

Les modifications pour tenir compte du nombre de jours maximum d'interruption pour la clientèle interruptible amèneront un déplacement des revenus d'équilibrage entre les tarifs et donc un impact sur l'interfinancement à l'intérieur de ce service. Les ajustements à la méthode de tarification de l'équilibrage ont pour effet de faire supporter aux clients continus une part plus importante des coûts d'équilibrage, soit près de 5,8 M$ de plus. Il est proposé de réduire la différence entre les tarifs de distributions interruptible et continu en ajustant les grilles tarifaires de façon à neutraliser le transfert de coûts.

[85] Pièce SCGM-11, document 2, page 21.

L'impact marginal de la modification des paramètres A et H versus les revenus tenant compte des modifications à la méthode de fonctionnalisation des coûts d'équilibrage entre la pointe et l'espace ainsi que de l'application d'une pointe aux clients interruptibles du volet 1B[86] est de 2,3 M$, selon le dossier tarifaire 2004.

Il est proposé de réduire la différence entre les tarifs de distributions interruptible et continu en ajustant les grilles tarifaires de façon à neutraliser cet impact marginal. Ce dernier dans le présent dossier est de 1,7 M$[87].

L'ajustement de la grille tarifaire de distribution pour tenir compte des changements apportés à l'équilibrage permet de garder indemnes les clients en termes de revenus totaux. La compensation au tarif de distribution a été faite par bloc de tarifs, tarifs D_1/D_M, tarifs D_3/D_4 et finalement tarif D_5. Il est impossible de modifier les grilles tarifaires de distribution de façon à neutraliser pour chaque client l'impact de la modification au tarif d'équilibrage. Ce dernier est établi en fonction du profil de consommation de chaque client, sauf pour les clients au tarif général D_1 alors que les grilles tarifaires de distribution ne sont pas établies selon les mêmes caractéristiques.

L'application, au service de distribution, d'une compensation équivalente au déplacement des revenus d'équilibrage amènera un effet inverse sur l'interfinancement à l'intérieur du service de distribution.

3.2 IMPACT SUR LE TARIF DE DISTRIBUTION

En plus de l'ajustement des grilles tarifaires de distribution, SCGM propose d'éliminer la distinction au tarif de distribution D_5 entre les volets 1A et 1B.

Avec le nouveau tarif d'équilibrage proposé, qui amène un ajustement aux paramètres A et H pour les clients interruptibles ainsi que le nouveau calcul de la pointe pour les clients au volet 1B, il n'y a plus de raison d'avoir une grille tarifaire du service de distribution D_5 différente selon le volet.

86 Voir section 4.2 de la présente décision.
87 Pièce SCGM-11, document 2.12.

3.3 PARTICULARITÉS ADDITIONNELLES

SCGM propose que les prix moyens par tarif et par volet dans le cas du tarif interruptible soient établis lors du dossier tarifaire, inscrits au texte des tarifs et appliqués dans les situations suivantes :

- nouveau client qui s'engage auprès du distributeur en cours d'année financière;
- client existant au 1er octobre ayant moins de 12 mois d'historique au moment de l'établissement du prix, soit au 1er octobre;
- client existant au 1er octobre pour lequel la consommation est de 0 m³ pour les 12 mois, au moment de l'établissement du prix, soit au 1er octobre.

Il est également proposé que le prix d'équilibrage soit révisé en cours d'année à la suite de tout changement contractuel au service de distribution interruptible qui entraîne un changement de sous-tarif ou un passage du volet 1A au volet 1B et vice versa, ou si le client passe d'un service continu à un service interruptible et vice versa.

3.4 AJUSTEMENT RELIÉ AUX INVENTAIRES

Le calcul mensuel actuel de l'ajustement relié aux inventaires est maintenu en utilisant les paramètres A et H du tarif d'équilibrage, après transposition, le cas échéant.

3.5 NORMALISATION DE LA TEMPÉRATURE

La méthode de normalisation de la température devra être adaptée. Actuellement, les revenus d'équilibrage sont normalisés afin de tenir compte de l'impact monétaire d'une variation de la température. Dans le cas du service d'équilibrage, deux aspects influencent la génération des revenus : le niveau de consommation et la répartition de cette consommation en cours d'année. Ainsi, non seulement des volumes retirés en plus ou en moins à cause de températures sous ou au-dessus des températures normales entraîneront-ils des revenus différents de la normale, mais la façon dont ces volumes seront répartis entre les mois influera également.

La proposition d'appliquer un prix moyen pour chacun des clients pour les 12 mois de l'année financière, rend inutile la détermination d'un prix d'équilibrage sous des températures normales. En effet, les variations de température n'auraient plus d'impact en cours d'année sur la consommation journalière moyenne annuelle, sur la consommation journalière moyenne d'hiver et sur la consommation journalière de pointe, paramètres A, H et P respectivement et donc sur les prix.

Par contre le niveau de consommation des clients serait encore influencé par les variations de température. Les revenus d'équilibrage devront donc toujours être normalisés, mais seulement à partir d'une normalisation des volumes.

4. SERVICE DE DISTRIBUTION D_1 ET D_M

Pour tous les clients du tarif D_1, exception faite des clients résidentiels et institutionnels, et pour ceux du tarif D_M, les frais de base passent de 55 ¢/compteur/jour à 45 ¢/compteur/jour. Pour les clients résidentiels et institutionnels du tarif D_1, les frais de base passent de 28 ¢/compteur/jour à 27 ¢/compteur/jour.

Le taux unitaire du premier palier (0 à 30 m³/jour) demeure inchangé, toutefois les taux unitaires des autres paliers sont ajustés afin de générer les mêmes revenus totaux.

La proposition entraîne très peu de modifications sur la facture totale des clients, sauf pour les clients consommant moins de 1 095 m³/année qui verront leur facture diminuer de près de 2 %. Malgré l'augmentation de l'interfinancement, ce niveau se justifie par l'intégration de certaines mesures pour favoriser l'efficacité énergétique et l'amélioration de la situation concurrentielle dans certains créneaux spécifiques.

5. STRUCTURE TARIFAIRE ET EFFICACITÉ ÉNERGÉTIQUE

Afin d'atténuer certains « désincitatifs » à l'efficacité énergétique, SCGM propose d'implanter les modifications suivantes aux structures tarifaires :

- l'assouplissement des seuils d'accès aux tarifs; et
- la révision des engagements contractuels reliés aux obligations minimales annuelles (OMA) et au volume souscrit pour la portion marginale des baisses de consommation réalisées dans le cadre d'un programme d'efficacité énergétique (PEÉ).

5.1 CLIENTÈLE VISÉE PAR LES MODIFICATIONS PROPOSÉES

Les modifications proposées s'appliqueront uniquement aux clients qui prendront part, après le 1er octobre 2004, à un PEÉ encadré par le PGEÉ ou par le FEÉ et pour lequel la quantification des économies d'énergie s'avère possible.

5.2 RÉDUCTION DU SEUIL D'ACCÈS

SCGM propose de maintenir, pour le client qui rencontre les conditions ci-dessus, l'accès au tarif actuel même si sa consommation est réduite.

5.3 RÉDUCTION DE L'OMA DES CLIENTS AUX TARIFS D_1, D_M ET D_5

SCGM propose qu'au moment de l'adhésion au PEÉ, le volume utilisé dans le calcul de l'OMA de distribution et de transport puisse être diminué d'un volume équivalent à la baisse marginale prévue par l'application du programme.

Cette nouvelle approche permet de réduire l'OMA devant être respectée par le client, tout en maintenant le pourcentage d'OMA à son niveau actuel, laissant ainsi intact le pourcentage de réduction pour l'OMA.

Dans le cas d'une adhésion à un PEÉ par un client au tarif D_M, SCGM propose d'accepter une révision du volume projeté utilisé pour le calcul de l'OMA même s'il s'est écoulé moins de 12 mois depuis la dernière révision.

Cette proposition constitue une dérogation aux conditions actuelles qui prévoient qu'un client peut réviser son pourcentage d'OMA une première fois n'importe quand après son adhésion au tarif D_M puis, par la suite, à intervalles minimums de 12 mois.

Les OMA requises pour permettre l'atteinte d'un niveau minimal de revenu dans le cas des clients au service général de distribution D_1 ne sont pas touchées par les modifications proposées. Il en est de même dans le cas des clients au tarif D_M, lorsque de telles OMA sont fixées en ajout de l'OMA tarifaire.

5.4 RÉDUCTION DU VOLUME SOUSCRIT ET DE L'OMA DE TRANSPORT AUX TARIFS D_3 ET D_4

Au moment de l'adhésion à un PEÉ, il est proposé que :

- le volume souscrit puisse être diminué d'un volume équivalent à la baisse marginale prévue par l'application du PEÉ et que ce volume souscrit révisé puisse être inférieur à 333 m³/jour;
- le volume annuel utilisé dans le calcul de l'OMA de transport puisse être diminué d'un volume équivalent à la baisse marginale prévue par l'application du PEÉ.

Les restrictions prévues en 5.3 concernant l'OMA requise pour permettre l'atteinte d'un niveau minimal de revenu s'appliquent.

5.5 DÉTERMINATION DE LA BAISSE POUR AJUSTER LE SEUIL D'ACCÈS AUX TARIFS ET LES MODALITÉS CONTRACTUELLES DU CLIENT

La diminution du seuil d'accès et des modalités contractuelles est limitée à un niveau équivalent à la baisse marginale. La baisse marginale est évaluée en faisant la différence entre la consommation d'un client résultant de la mise en place de la mesure plus performante et la consommation d'un client à la suite de l'implantation d'une mesure dite normale.

5.6 DÉTERMINATION DE LA DURÉE RECONNUE DE LA MESURE D'EFFICACITÉ ÉNERGÉTIQUE POUR AJUSTER À LA BAISSE LE SEUIL D'ACCÈS AU TARIF

La durée de vie doit être déterminée *a priori*, indépendamment des conditions particulières à chaque client. Aucune vérification ne doit être faite chez le client afin de vérifier si les appareils installés sont toujours en place et utilisés. SCGM propose que la baisse marginale reconnue le soit pour une durée moyenne, évaluée *a priori*, pour le type de mesure d'efficacité énergétique implantées.

6. TEXTE DES TARIFS

Le texte des tarifs intègre les modifications proposées aux structures tarifaires. Il inclut également des modifications à l'écriture visant simplement à uniformiser le texte ou à en faciliter la lecture et la compréhension.

Le texte des tarifs contient une proposition de modification de l'article 2 « Tarif » de la section « Fourniture – C) Service de gaz d'appoint » afin de permettre au distributeur de contracter lui-même la fourniture et le gaz de compression requis pour répondre au besoin en gaz d'appoint d'un client et de lui revendre le tout au prix réel.

ANNEXE 2

RÉSUMÉ DES PROPOSITIONS RELATIVES AU PROGRAMME DE PRODUITS DÉRIVÉS FINANCIERS

Annexe 2 (2 pages)

J.-N. V. _______

A. C.-V. _______

F. R. _______

ANNEXE 2

RÉSUMÉ DES PROPOSITIONS DU PROGRAMME DE DÉRIVÉS FINANCIERS

OUTILS AUTORISÉS

- Contrat d'échange à prix fixe
- Achat et vente d'options d'achat et de vente
- Combinaison des outils précités

BALISE TEMPORELLE

- Couverture maximale : ne dépassant pas le 30 octobre 2008
  - ? La balise temporelle se voit attribuer une date maximale au lieu d'être une période mobile de 36 mois. Couverture maximale : 48 mois
  - ? En moyenne, l'augmentation de la base temporelle est de 6 mois

ENVELOPPE BUDGÉTAIRE POUR LE PAIEMENT DES PRIMES

- Maximum de 1,5 % du coût annualisé du service de fourniture de gaz naturel de SCGM et de gaz de compression

PRIX MAXIMAL POUR CONTRATS D'ÉCHANGE ET PLANCHERS DE COLLIERS

- 6,91 $/GJ à AECO équivalent MTL

PRIX D'EXERCICE MAXIMAL POUR L'ACHAT DES OPTIONS AVEC UNE ÉCHÉANCE INFÉRIEURE À

- Octobre 2005 : 11,00 $/GJ à AECO
- Octobre 2006 : 10,43 $/GJ à AECO (1)
- Octobre 2007 : 9,97 $/GJ à AECO (1)
- Octobre 2008 : 9,60 $/GJ à AECO (1)

(1) CIBC World Markets Energy Update, Thursday, March 25, 2004.

Source: Pièce SCGM5, document 1, page 2.

BALISES VOLUMÉTRIQUES
DOSSIER TARIFAIRE 2004

	Nov. 2004 Oct. 2005	Nov. 2005 Oct. 2006	Nov. 2006 Oct. 2007	Nov. 2007 Oct.2008
Service de fourniture de gaz naturel de SCGM et de gaz de compression				
En PJ/an	98,790	89,638 [(1)]	81,634 [(1)]	73,799 [(1)]
En 10^6 m³/an	2 607	2 366	2 147	1 948
Portefeuille cible de protection (%) [(2)]	20 – 75 %	0 – 56 %	0 – 42 %	0 – 32 %
Volumes annuels à protéger				
En PJ/an	20 – 74	0 – 50	0 – 34	0 – 23
En 10^6 m³/an	521 – 1 955	0 – 1 331	0 – 906	0 – 616
Volumes maximums – transactions mensuelles (1/6 des volumes annuels)				
En PJ/mois	12,349	8,404	5,717	3,892
En 10^6 m³/mois	326	222	151	103

(1) Estimé en fonction de la courbe de déplacement calculée.

(2) Établi en fonction du facteur d'incertitude calculé.

Source : Pièce SCGM-5, document 1, page 2.