NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

55 Kenmount Road
PO Box 8910
St. John's, Newfoundland
A1B 3P6
Business: (709) 737-5600
Facsimile: (709) 737-2974
www.newfoundlandpower.com

DELIVERED BY HAND

September 29, 2005

Board of Commissioners of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NF A1A 5B2

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies and Gentlemen:

Re: Newfoundland Power's 2006 Accounting Policy Application

Enclosed are 15 copies of Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") 2006 Accounting Policy Application (the "Application").

A. Description of the Filing

Application Overview

In June 2005, Newfoundland Power resolved a longstanding tax dispute concerning its historical policy of revenue recognition for income tax purposes. Since 1998, Newfoundland Power's revenue recognition policy has been before the Board on a number of occasions. The Board has indicated its intention to review that policy and any issues arising from the tax dispute, including potential liabilities or benefits to customers, following resolution of the dispute.

The principal focus of the Application is a proposed change in accounting policy for revenue recognition for regulatory purposes commencing in 2006. Newfoundland Power is proposing it change to an accrual policy for revenue recognition (the "Accrual Method"). The Accrual Method is current Canadian public utility practice.

The proposed change in accounting policy will give rise to a number of transitional issues and consequential matters which will require Board consideration.

The principal transition issue relates to an accounting accrual of approximately $24.3 million which arises as a result of the proposed policy change (the "2005 Unbilled Revenue"). In the Application, Newfoundland Power is proposing that approximately $9.6 million of this accrual be applied to meet increased depreciation expense in 2006. The primary cause of the increased depreciation expense is the 2005 conclusion of the 3-year depreciation true-up authorized in Order No. P.U. 19 (2003). The proposal seeks, in effect, to substitute one accrual for another in 2006. This will defer a customer rate increase in 2006 which would be otherwise necessary to recover increased depreciation expense.

The remaining transitional issues and consequential matters also flow out of the proposed adoption of the Accrual Method. They are aimed at ensuring that the effects of the proposed change in accounting policy for revenue recognition are fully addressed.

John Browne, an expert in regulatory accounting, has filed a report accompanying the Application, expressing his opinion on the appropriateness of the proposals submitted by the Company.

Compliance Matters

By Order Nos. P.U. 36 (1998-99), P.U. 28 (1999-2000) and P.U. 19 (2003) the Board ordered, in effect, that Newfoundland Power file a revenue recognition study (the "Revenue Recognition Study") upon resolution of an outstanding tax dispute. The Revenue Recognition Study is included with the filing.

In Order No. P.U. 36 (1998-99), the Board ordered Newfoundland Power to establish an Unbilled Revenue Increase Reserve (the "Reserve") and that the disposition of the Reserve would be dealt with in the future order arising from the review of Newfoundland Power's revenue recognition policy. A proposal to deal with the disposition of the Reserve is included in the Application.

By Order No. P.U. 19 (2003), the Board, in effect, found that the asset rate base method (the "ARBM") should be used to calculate Newfoundland Power's rate base and ordered Newfoundland Power to review the matter of adoption of the ARBM no later than at its next general rate application. The proposed change to the Accrual Method of revenue recognition has effects on the Company's invested capital and rate base. These matters are addressed in the Application and the ARBM review is, accordingly, included in the filing.

The Application seeks approval of forecast 2006 values for rate base and invested capital for use in the automatic adjustment formula. In the past, such approval has typically been sought in Capital Budget Applications. Given the subject matter of the Application and its impact on these forecast values, the Application provides the appropriate context for consideration of them.

B. Order Sought in the Application

In the Application, Newfoundland Power is seeking an order approving:

(a) Newfoundland Power's adoption of the Accrual Method of revenue recognition commencing in 2006;

(b) the application of $9,579,000 of 2005 Unbilled Revenue to Newfoundland Power's 2006 revenue for regulatory purposes;

(c) the application of $295,000 of 2005 Unbilled Revenue to dispose of the current balance in the Reserve in 2006;

(d) that the average value of the unrecognized 2005 Unbilled Revenue be deducted from rate base commencing in 2006; and

(e) a 2006 forecast for rate base of $744,326,000 and a 2006 forecast for invested capital of $745,752,000 to be used in the Formula in calculating Newfoundland Power's return on rate base.

C. Filing Details and Circulation

The enclosed material has been provided in a binder with appropriate tabbing. For convenience, additional materials such as Responses to Requests for Information will be provided on three-hole punched paper.

A PDF file of the Filing will be forwarded to the Board in due course.

A copy of the Filing has been forwarded directly to Mr. Geoff Young of Newfoundland & Labrador Hydro and Mr. Thomas J. Johnson, the Consumer Advocate.

We trust the foregoing and enclosed are found to be in order. If you have any questions on the Filing, please contact us at your convenience.

Yours very truly,

Peter Alteen
Vice President, Regulatory Affairs
& General Counsel

Enclosures

c. Geoffrey P. Young
General Counsel
Newfoundland & Labrador Hydro

Thomas J. Johnson
Consumer Advocate
O'Dea Earle Law Offices

IN THE MATTER OF the *Public Utilities Act,* (the "Act"); and

IN THE MATTER OF the accounting policy of Newfoundland Power Inc. concerning revenue recognition and matters related thereto; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 67, 69, 78 and 80 of the Act:

(a) approving changes in accounting policy concerning revenue recognition to be effective for 2006 and subsequent years;
(b) approving the recognition of $9,579,000 in 2005 Unbilled Revenue as revenue for regulatory purposes for 2006;
(c) approving disposition of the balance of the Unbilled Revenue Increase Reserve; and
(d) approving revised values for rate base and invested capital for use in the automatic adjustment formula for the calculation of return on rate base for 2006 pursuant to Order No. P.U. 19 (2003).

2006 Accounting Policy Application

NEWFOUNDLAND POWER
A FORTIS COMPANY

IN THE MATTER OF the *Public Utilities Act,* (the "Act"); and

IN THE MATTER OF the accounting policy of Newfoundland Power Inc. concerning revenue recognition and matters related thereto; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 67, 69, 78 and 80 of the Act:

(a) approving changes in accounting policy concerning revenue recognition to be effective for 2006 and subsequent years;
(b) approving the recognition of $9,579,000 in 2005 Unbilled Revenue as revenue for regulatory purposes for 2006;
(c) approving disposition of the balance of the Unbilled Revenue Increase Reserve; and
(d) approving revised values for rate base and invested capital for use in the automatic adjustment formula for the calculation of return on rate base for 2006 pursuant to Order No. P.U. 19 (2003).

TO: The Board of Commissioners of Public Utilities (the "Board")

THE APPLICATION OF Newfoundland Power Inc. ("Newfoundland Power") **SAYS THAT:**

A. Background

1. Newfoundland Power is a corporation duly organized and existing under the laws of the Province of Newfoundland and Labrador, is a public utility within the meaning of the Act, and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. By Order Nos. P.U. 36 (1998-99), P.U. 28 (1999-2000) and P.U. 19 (2003) the Board ordered, in effect, that Newfoundland Power file a revenue recognition study (the "Revenue Recognition Study") upon resolution of an outstanding dispute with the Canada Revenue Agency (the "CRA").

3. In Order No. P.U. 36 (1998-99), the Board ordered Newfoundland Power to establish an Unbilled Revenue Increase Reserve (the "Reserve") and that the disposition of the Reserve would be dealt with in the future order arising from the review of Newfoundland Power's revenue recognition policy.

4. By Order Nos. P.U. 16 (1998-99), P.U. 36 (1998-99) and P.U. 19 (2003), the Board ordered, in effect, that an automatic adjustment formula be established to set the electrical rates and allowed rates of return for Newfoundland Power based upon changes in long term Government of Canada bond yields (the "Formula").

5. By Order No. P.U. 19 (2003), the Board, in effect, found that the asset rate base method (the "ARBM") should be used to calculate Newfoundland Power's rate base and ordered Newfoundland Power to review the matter of adoption of the ARBM no later than at its next general rate application (the "ARBM Review").

6. By Order No. P.U. 19 (2003), the Board, in effect, approved Newfoundland Power's amortization of a $17,200,000 depreciation reserve variance over a three year period commencing in 2003 and concluding in 2005.

B. Accounting Policy for Revenue Recognition

7. Newfoundland Power currently recognizes revenue as its customers are billed (the "Billed Method"). Current Canadian public utility practice is for utilities to recognize revenue as power is delivered to customers (the "Accrual Method").

8. The primary issue in the outstanding dispute between Newfoundland Power and the CRA was the appropriateness of Newfoundland Power's use of the Billed Method of revenue recognition for the purposes of calculating tax payable under the *Income Tax Act (Canada).*

9. On June 1, 2005, Newfoundland Power and the CRA resolved the outstanding dispute described in paragraph 8 of this Application (the "Tax Settlement").

10. The Revenue Recognition Study is filed with this Application.

11. In this Application, Newfoundland Power proposes that it adopt the Accrual Method of revenue recognition for regulatory purposes commencing in 2006.

C. Transitional Matters

12. Adoption of the Accrual Method of revenue recognition for regulatory purposes will give rise to a forecast accounting accrual of $24,262,400 as of December 31, 2005 (the "2005 Unbilled Revenue").

13. Newfoundland Power's 2006 depreciation expense is forecast to exceed 2005 depreciation expense by $6,950,000.

14. The Reserve was established to account for the impact of the revenue recovery lag inherent between the Billed Method and Accrual Method of revenue recognition when customer electricity rates change. The current balance in the Reserve is $295,000.

15. In this Application, Newfoundland Power is proposing that the forecast 2005 Unbilled Revenue of $24,262,400 be dealt with over a transition period as follows:

    (i) the amount of $9,579,000 be recognized in 2006 to satisfy the increased forecast 2006 depreciation expense described in paragraph 13 together with appropriate tax effects;

    (ii) the amount of $295,000 be applied in 2006 to eliminate the current balance in the Reserve as described in paragraph 14; and

    (iii) the disposition of the forecast remaining balance of $14,388,400 be determined by the Board in a future order.

D. 2006 Rate Base and Invested Capital

16. Adoption of the Accrual Method of revenue recognition in 2006 as proposed in this Application will affect the calculation of rate base and invested capital for Newfoundland Power.

17. The ARBM Review is filed with this Application.

18. In this Application, Newfoundland Power proposes that a 2006 forecast for rate base of $744,326,000 and a 2006 forecast for invested capital of $745,752,000 be used in the Formula for the calculation of the 2006 return on rate base.

19. No changes to the Formula are proposed in this Application.

E. Order Requested

20. In this Application, Newfoundland Power requests the Board make an order approving:

    (a) pursuant to Section 67 of the Act, adoption of the Accrual Method of revenue recognition commencing in 2006;

    (b) pursuant to Sections 69 and 80 of the Act, the recognition for regulatory purposes of $9,579,000 of the 2005 Unbilled Revenue as 2006 revenue;

    (c) pursuant to Sections 69(3) and 80 of the Act, the application of $295,000 of the 2005 Unbilled Revenue in 2006 to dispose of the current balance in the Reserve;

    (d) pursuant to Sections 78 and 80 of the Act, that the average value of the unrecognized 2005 Unbilled Revenue be deducted from rate base commencing in 2006;

(e) pursuant to Sections 78 and 80 of the Act, a 2006 forecast for rate base of $744,326,000 and a 2006 forecast for invested capital of $745,752,000 to be used in the Formula for the calculation of 2006 return on rate base; and

(f) such further, other or alternate matters which may, upon the record of proceedings in respect of this Application, appear just and reasonable in all of the circumstances.

21. The order requested in this Application, if granted by the Board, will not result in a change in the electricity rates charged by Newfoundland Power to its customers in 2006.

F. Communications

22. Communication with respect to this Application should be forwarded to the attention of Ian Kelly, Q.C. and Peter Alteen, counsel to Newfoundland Power.

DATED at St. John's, Newfoundland and Labrador, this 29th day of September, 2005.

NEWFOUNDLAND POWER INC.

Ian Kelly, Q.C. and Peter Alteen
Counsel to Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's, NL A1B 3P6

Telephone: (709) 737-5859
Telecopier: (709) 737-2974

IN THE MATTER OF the *Public Utilities Act,* (the "Act"); and

IN THE MATTER OF the accounting policy of Newfoundland Power Inc. concerning revenue recognition and matters related thereto; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 67, 69, 78 and 80 of the Act:
(a) approving changes in accounting policy concerning revenue recognition to be effective for 2006 and subsequent years;
(b) approving the recognition of $9,579,000 in 2005 Unbilled Revenue as revenue for regulatory purposes for 2006;
(c) approving disposition of the balance of the Unbilled Revenue Increase Reserve; and
(d) approving revised values for rate base and invested capital for use in the automatic adjustment formula for the calculation of return on rate base for 2006 pursuant to Order No. P.U. 19 (2003).

AFFIDAVIT

I, Karl Smith, of St. John's in the Province of Newfoundland and Labrador, Chartered Accountant, make oath and say as follows:

1. That I am employed with Newfoundland Power Inc. as President and Chief Executive Officer.

2. To the best of my knowledge, information and belief, all matters, facts and things set out in this Application are true.

SWORN to before me at St. John's
in the Province of Newfoundland and
Labrador this 29th day of September, 2005:

Barrister

Karl Smith

IN THE MATTER OF the *Public Utilities Act,* (the "Act"); and

IN THE MATTER OF the accounting policy of Newfoundland Power Inc. concerning revenue recognition and matters related thereto; and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 67, 69, 78 and 80 of the Act:
(a) approving changes in accounting policy concerning revenue recognition to be effective for 2006 and subsequent years;
(b) approving the recognition of $9,579,000 in 2005 Unbilled Revenue as revenue for regulatory purposes for 2006;
(c) approving disposition of the balance of the Unbilled Revenue Increase Reserve; and
(d) approving revised values for rate base and invested capital for use in the automatic adjustment formula for the calculation of return on rate base for 2006 pursuant to Order No. P.U. 19 (2003).

Company Evidence

NEWFOUNDLAND POWER
A FORTIS COMPANY

2006 ACCOUNTING POLICY APPLICATION

CONTENTS

2006 ACCOUNTING POLICY APPLICATION

CONTENTS

EXHIBIT LIST

PART 1: APPLICATION OVERVIEW

1.1 Introduction

In June 2005, Newfoundland Power resolved a longstanding tax dispute concerning its historical policy of revenue recognition for income tax purposes. At issue was over $16 million in income tax and interest related to Newfoundland Power's income tax accounting in the 1990s. Resolution of this dispute will not require Newfoundland Power to pay any additional amount in respect of its historical revenue recognition policy. The resolution is beneficial for both Newfoundland Power and its customers.

Since 1998, Newfoundland Power's revenue recognition policy has been before the Board on a number of occasions. The Board has indicated its intention to review that policy and any issues arising from the tax dispute, including potential liabilities or benefits to customers, following resolution of the dispute. This Application addresses the Company's current accounting policy for revenue recognition for regulatory purposes and proposes it be changed.

Under the *Public Utilities Act*, the Board regulates both the revenue and returns of Newfoundland Power. The accounting relationship between revenue and returns is an essential element of cost of service regulation. The proposed change in the accounting policy for revenue recognition for regulatory purposes necessarily requires consideration of the potential impacts on that accounting relationship. This Application addresses the impacts on that accounting relationship.

1.2 The Application

The principal focus of this Application is a proposed change in accounting policy for revenue recognition for regulatory purposes. If approved by the Board, the proposed change in accounting policy will require the Board to consider a number of transitional issues and consequential matters. An overview of the proposals contained in this Application follows.

Accounting Policy Change: Newfoundland Power is proposing to adopt the accrual method of revenue recognition for regulatory purposes in 2006. The proposed revenue recognition policy is consistent with established regulatory principles, generally accepted accounting principles and current Canadian public utility practice.

The proposed revenue recognition policy will result in Newfoundland Power's revenue and expenses both being recognized on the same calendar basis. This will eliminate historical complications in rate administration caused by differences in the timing of revenue and expense recognition.

Transitional Issues: The proposed change in accounting policy for regulatory purposes will require consideration of a balance sheet accrual of approximately $24.3 million as of December 31, 2005 (the "2005 Unbilled Revenue"). This accrual can, within limits, be used to offset Newfoundland Power's future revenue requirements and represents a potential future benefit for Newfoundland Power's customers.

Newfoundland Power is proposing to apply approximately $9.6 million of the 2005 Unbilled Revenue to offset rising depreciation expense and related income tax effects in 2006. This effectively results in the substitution of one accounting accrual for another. The $9.6 million accrual represents approximately 2.3% of 2006 forecast revenue from rates. This proposal defers an otherwise necessary rate increase in 2006, which provides tangible benefits to Newfoundland Power's customers in that year.

Newfoundland Power is proposing that the $295,000 balance in the Unbilled Revenue Increase Reserve be applied against the 2005 Unbilled Revenue. This will dispose of the reserve balance without affecting customer rates.

Newfoundland Power is proposing that disposition of the remaining 2005 Unbilled Revenue of approximately $14.4 million be determined by the Board in a future order. Currently, the Company expects its next general rate application to be filed in 2006. This approach will enable the Board to maintain continued supervision over the remaining 2005 Unbilled Revenue.

Newfoundland Power is proposing that the average of the remaining 2005 Unbilled Revenue, reflected in the Company's balance sheets as a liability, be deducted from rate base. This will help ensure that an appropriate accounting relationship is maintained between Newfoundland Power's revenue and returns through a transition period.

Consequential Matters: The proposals in this Application also have implications for Newfoundland Power's adoption of the asset rate base method for calculating return on rate base.

The proposals will, among other things, address certain reconciling items between Newfoundland Power's invested capital and rate base, as ordered by the Board in Order No. P.U. 19 (2003).

Currently, the largest reconciling item between Newfoundland Power's invested capital and rate base is working capital. The proposed change in accounting policy will substantially reduce this difference. In this Application, Newfoundland Power is proposing that the second largest reconciling item, regulated common equity, be discontinued in calculating the return on rate base commencing in 2006. In addition, resolution of the tax dispute has resulted in the refund of the associated income tax deposit in 2005, eliminating the third largest reconciling item between the Company's invested capital and rate base.

Together, these changes will mark significant progress toward the adoption of the asset rate base method for Newfoundland Power. This will facilitate the filing of Newfoundland Power's next general rate application using the asset rate base method and thereby conclude the transition to the asset rate base method in a transparent manner.

The proposals contained in this Application affect the 2006 forecast values for rate base and invested capital of Newfoundland Power. These values are used in the operation of the automatic adjustment formula. While historically the Board has considered these values in its review of Newfoundland Power's annual capital budget application, the subject matter of this Application provides an appropriate context for considering these values. No changes to the automatic adjustment formula itself are proposed in this Application.

PART 2: APPLICATION CONTEXT

2.1 Accounting Standards for Newfoundland Power

Newfoundland Power must satisfy accounting standards for financial reporting, income tax and rate regulation. While these three sets of standards are formulated by different governing bodies and have different purposes, they are interrelated.

Recent developments affecting accounting standards should be reflected in Newfoundland Power's prospective accounting policy for revenue recognition for financial reporting, rate regulation and income tax purposes in a reasonably consistent and transparent manner.

This section of evidence provides a general overview of the accounting standards which affect Newfoundland Power and provides context for this Application.

2.1.1 Accounting Standards

Newfoundland Power is an investor owned regulated electric utility which participates in Canadian capital markets. As a result, Newfoundland Power is subject to accounting standards that govern financial reporting, rate regulation and income tax.

The primary accounting records of Newfoundland Power are the single source of the data necessary to satisfy each set of accounting standards.

While each set of accounting standards exists to serve a distinct accounting purpose, the standards themselves are not entirely distinct from each other. Financial reporting, for example, will be influenced by both regulatory and income tax standards. A general understanding of the different accounting standards and their purposes will assist in understanding the accounting issues raised in this Application.

Financial Reporting

In general, accounting standards governing financial reporting to Canadian securities regulators and investors are formulated by the Canadian Institute of Chartered Accountants (the "CICA").

Financial reporting is aimed primarily at providing investors with information to permit reasonable assessment of the amount, timing and certainty of future income, cash flows and financial obligations of an enterprise. The principal set of accounting standards by which this is achieved is generally accepted accounting principles ("GAAP"), for which the primary source is the CICA Handbook – Accounting.[1]

Currently, GAAP effectively permits the financial reporting of rate regulated enterprises to reflect regulatory accounting standards for the recognition of revenue and expenses. These accounting standards may differ from those required to be followed by enterprises not subject to rate regulation.

The Accounting Standards Board[2] of the CICA is currently reviewing issues surrounding the accounting for the effects of rate regulation. This matter is addressed in more detail in the report of JT Browne Consulting filed with this Application.[3]

---

1 The CICA Handbook – Accounting contains accounting standards applicable to all types of profit oriented enterprises and not-for-profit organizations. The Canada Business Corporations Act and provincial corporations and securities legislation generally require companies to prepare financial statements for their shareholders in accordance with GAAP as set out in the CICA Handbook – Accounting.

2 The Accounting Standards Board is an independent body with the authority to develop and establish standards and guidance governing financial accounting and reporting in Canada.

3 See Section 2, RAP vs GAAP, of the report of JT Browne Consulting.

Income Tax

The primary purpose of income tax standards is the determination of government revenue. GAAP plays a role in the measurement of income for income tax purposes. However, GAAP is superseded by the standards governing accounting for income tax purposes.

Standards governing income tax accounting are generally established by the *Income Tax Act (Canada)* and by the variety of rulings and interpretations of that legislation by the Canada Revenue Agency (the "CRA") and the courts.

Income tax accounting standards can differ significantly from GAAP and regulatory accounting standards. For example, in the computation of income for income tax purposes, income tax accounting standards permit the deduction of capital asset depletion through capital cost allowance. Pursuant to GAAP and regulatory accounting standards, asset depletion is recognized through depreciation expense. Capital cost allowance and depreciation expense can differ significantly.

Rate Regulation

Standards governing Newfoundland Power's regulatory accounting are generally established by the Board as a result of authority granted under the *Public Utilities Act*.

The primary purpose of regulation is to strike a balance between the interests of consumers and investors, particularly in the context of establishing prices. Regulatory accounting standards seek to provide the accounting tools to help regulators strike this balance. In addition, they can ensure consistency of accounting information over time and amongst utilities.

The genesis of regulatory accounting standards is reflected in systems of accounts, accepted regulatory practice and specific regulatory rulings. GAAP also plays a role in defining regulatory accounting standards. However, regulators have the ability to deviate from GAAP in setting regulatory accounting standards to better balance consumer and investor interests.

While regulatory accounting standards govern regulatory matters, they do not necessarily affect financial reporting or income tax. For example, regulators typically will not permit charitable donations by a utility to be recognized for regulatory purposes. Such donations are, however, clearly recognizable for both financial reporting and income tax purposes.

The relationship between accounting standards for financial reporting and rate regulation is addressed in more detail in the report of JT Browne Consulting filed with this Application.[4]

2.1.2 Methods of Revenue Recognition

Billing for utility service is practically required to be performed on a continuous basis. However, at any point in time the aggregate amount and value of electrical service delivered to customers can be estimated.

Historically, regulated utilities have recognized revenue by one of two broad methods.

[4] See Section 2, RAP vs GAAP, of the report of JT Browne Consulting.

One method is to recognize revenue as customers are billed for the service provided to them. This method of recognizing revenue as it is ***billed*** (the "Billed Method") is Newfoundland Power's current accounting policy for revenue recognition. The Billed Method has been consistently applied by Newfoundland Power for financial reporting, regulatory and income tax purposes even prior to the Company's creation by amalgamation in 1966.

The alternate method is to recognize revenue as service is delivered to customers (the "Accrual Method"). The Accrual Method is based upon the premise that once the service is delivered, the resultant revenue has been earned regardless of whether a bill has been rendered or payment received. The service provider's right to be paid is said to have ***accrued***. Revenue recognition using the Accrual Method is accepted Canadian public utility practice.

2.2 The Tax Settlement

In June 2005, Newfoundland Power settled a longstanding dispute concerning its historical practice of revenue recognition for income tax purposes. Over $16 million in income tax and interest related to the 1990s was at issue in the dispute.

Newfoundland Power's settlement of the tax dispute is the catalyst for this Application.

This section of evidence outlines the background of the dispute and the terms of the settlement.

2.2.1 Background

In 1995, the CRA reassessed Newfoundland Power's income tax returns for 1988 through 1993 on a number of grounds, the majority of which related to the Company's treatment of general expenses capital ("GEC") for income tax purposes and the appropriateness of the Company's use of the Billed Method to recognize revenue (the "Original Reassessments"). Newfoundland Power objected to the Original Reassessments.

In 2000, the CRA agreed to abandon the position it took in the Original Reassessments relating to the Company's treatment of GEC for income tax purposes. GEC was the largest issue raised in the Original Reassessments.

Following resolution of the GEC matter in 2000, the CRA issued a revised reassessment for 1993 which maintained that the Company's use of the Billed Method to recognize revenue was inappropriate for income tax purposes. Subsequently, in 2001, the CRA also reassessed the Company for 1994 through 1999 on the basis of the Company's revenue recognition policy. The effect of the reassessments for 1993 through 1999 (the "Revised Reassessments")[5] was to calculate Newfoundland Power's income tax for those years using the Accrual Method of revenue recognition. At December 31, 2004, the contingent liability associated with the Revised Reassessments was approximately $16.2 million.

In June 2005, Newfoundland Power and the CRA negotiated a settlement of all outstanding matters in dispute, including those raised in the Revised Reassessments, regarding the Company's method of recognizing revenue for income tax purposes (the "Tax Settlement").

[5] In addition to these reassessments, in May 2000 the CRA also reassessed Newfoundland Power in respect of costs associated with an employee relocation from Carbonear to St. John's in 1992. This matter, which involved an amount of $36,237, was abandoned by the CRA as part of the Tax Settlement (see paragraphs 1, 2 and 12 of Exhibit NP-1). It is not referred to further in this evidence.

2.2.2 The Tax Settlement

A copy of the Tax Settlement is Exhibit NP-1.

The essential provisions of the Tax Settlement are:

1. the CRA will abandon the Revised Reassessments; consent to discontinue the related proceedings in the Tax Court of Canada; and refund, with applicable interest, all amounts held on deposit by the CRA in relation to the Revised Reassessments;

2. Newfoundland Power will recognize revenue using the Accrual Method ***for income tax purposes*** commencing in 2006; and

3. in each of 2006, 2007 and 2008 Newfoundland Power will ***for income tax purposes*** recognize 1/3 of the 2005 Unbilled Revenue as taxable income.

Under the terms of the Tax Settlement, Newfoundland Power will pay no additional taxes, interest or penalties under the provisions of the *Income Tax Act (Canada)* as a result of the Revised Reassessments.

As a result of the Tax Settlement (i) the contingent liability of approximately $16 million associated with the Revised Reassessments is eliminated and (ii) Newfoundland Power will recognize income tax on the 2005 Unbilled Revenue prospectively over the period 2006 to 2008.

2.2.3 Income Tax Effects of the Tax Settlement

The Tax Settlement will give rise to prospective income tax obligations for Newfoundland Power. The *pro forma* income tax effects of these obligations for 2006 to 2008, detailed in Exhibit NP-2, are summarized in Table 1.

Table 1
Tax Settlement
***Pro Forma* Income Tax Effects**
2006 – 2008
(000s)

	2006	**2007**	**2008**
Income Tax Effects[6]	$3,086	$2,999	$3,016

There is no requirement that Newfoundland Power recognize the 2005 Unbilled Revenue for regulatory purposes in the same manner as it has agreed to for income tax purposes.[7] However, if Newfoundland Power does not recognize the 2005 Unbilled Revenue for regulatory purposes (i.e., it continues on the Billed Method of revenue recognition), the *pro forma* income tax effects set out in Table 1 will effectively represent increased income taxes payable by the Company.

Recognition of the 2005 Unbilled Revenue for regulatory purposes will permit the Company to offset the *pro forma* income tax effects set out in Table 1 without increasing revenue from rates. Recognition of $3,086,000 of the 2005 Unbilled Revenue will offset the *pro forma* 2006 income tax effects.

[6] Income Tax Effects include those related to (i) the recognition of the 2005 Unbilled Revenue for income tax purposes equally over 2006 – 2008 and (ii) the adoption of the Accrual Method of revenue recognition for income tax purposes commencing in 2006. See Exhibit NP-2.

[7] Use of the terms "recognize" or "recognition" in accounting broadly refers to reporting in any of the financial statements. In this evidence, the terms "recognize" or "recognition" used in relation to the 2005 Unbilled Revenue refers to reporting an amount of the 2005 Unbilled Revenue as revenue in Newfoundland Power's statement of earnings.

Offsetting the *pro forma* 2006 income tax effects with revenue from rates would increase taxable income by a like amount in 2006 and, in turn, increase 2006 income tax expense. An amount of \$4,831,000[8] in revenue from rates would be required to offset a \$3,086,000 increase in 2006 income tax expense. The difference of \$1,745,000[9] would be required to pay additional income taxes.

To the extent Newfoundland Power recognizes the 2005 Unbilled Revenue for regulatory purposes, it effectively displaces cash revenue from its customers upon which income tax would be payable. Recognizing a sufficient amount of the 2005 Unbilled Revenue in 2006 to offset the *pro forma* income tax effects set out in Table 1 is, from a consumer perspective, the least cost means of recovering the tax obligations arising from the Tax Settlement.

2.3 Implications for this Application

From a financial reporting perspective, recent developments in GAAP will require Newfoundland Power to disclose the 2005 Unbilled Revenue on its balance sheets as of December 31, 2005. Further details can be found in the report of JT Browne Consulting filed with this Application.[10]

The Tax Settlement resolved a longstanding dispute with respect to the Company's practice of revenue recognition for income tax purposes. As a result of the Tax Settlement, Newfoundland Power is not required to pay any additional amount in respect of its historical revenue recognition practice, therefore providing benefits to Newfoundland Power and its customers.

---

8 Equals (\$3,086,000/(1-tax rate)) or (\$3,086,000/(1 - .3612)).
9 Equals (\$4,831,000 x tax rate) or (\$4,831,000 x .3612).
10 See Section 2, RAP vs GAAP, of the report of JT Browne Consulting.

From an income tax perspective, Newfoundland Power has agreed, commencing in 2006, to recognize revenue on an accrual basis for the purpose of calculating income tax expense in accordance with the *Income Tax Act (Canada)*. A transition period has been established over which Newfoundland Power will recognize the 2005 Unbilled Revenue for income tax purposes.

The proposals in this Application are related to a proposed change in accounting policy for revenue recognition for regulatory purposes. They are transparently aligned with the recent accounting developments affecting financial reporting and income tax.

PART 3: APPLICATION PROPOSALS

3.1 Accounting Policy for Revenue Recognition

Newfoundland Power's current accounting policy is to recognize revenue as customers are billed for service. This policy is not consistent with that of most other Canadian utilities, which recognize revenue as service is delivered to customers.

In this Application, Newfoundland Power is proposing to change its accounting policy, commencing in 2006, to recognize revenue for regulatory purposes as service is delivered to customers.

This section of evidence describes the proposed change in Newfoundland Power's accounting policy for revenue recognition for regulatory purposes.

3.1.1 Policy Analysis

Currently, Newfoundland Power recognizes revenue using the Billed Method. However, the Company recognizes expenses on an accrual basis. This results in a timing difference between the recognition of Newfoundland Power's revenue and expenses.[1]

For Newfoundland Power, the use of the Accrual Method of revenue recognition will result in a better *matching* of the Company's revenue and expenses. The use of the Accrual Method will also move Newfoundland Power's revenue recognition policy into the mainstream of Canadian public utility practice.

[1] The timing difference results from the fact that in each year Newfoundland Power's billings on average reflect service deliveries from mid-December in the previous year to mid-December in the current year. Expenses, on the other hand, in each year effectively reflect costs, including purchased power costs, incurred from January 1st to December 31st in the current year.

Newfoundland Power's aggregate billings to its customers at any point in time will lag the value of aggregate service deliveries to customers by approximately ½ month.[2] Under the Billed Method of revenue recognition, this effectively means that approximately ½ of the aggregate value of electrical service delivered to customers in December in each year is not recognized as revenue until January of the following year when billed. Under the Accrual Method, this revenue would be accrued and recognized in December. The differing revenue recognition methods do not materially impact cash flows. In accounting terms, the difference is essentially a timing difference.

3.1.2 The Revenue Recognition Study

The Revenue Recognition Study is Exhibit NP-3.

The Revenue Recognition Study indicates that current Canadian public utility practice for financial reporting and regulatory purposes is the Accrual Method of revenue recognition.[3] The Accrual Method is also consistent with GAAP and regulatory accounting principles.[4]

3.1.3 Prospective Revenue Impact of Accounting Policy Change

Newfoundland Power has evaluated the prospective impact on revenue of changing its revenue recognition policy for regulatory purposes from the Billed Method to the Accrual Method.

---

2 This lag was recognized by the Board in Order No. P.U. 36 (1998-99) at pp. 90 *et. seq.* and Order No. P.U. 19 (2003) at pp. 86 *et. seq*. In Order No. P.U. 36 (1998-99), the Board ordered Newfoundland Power, to (i) establish an Unbilled Revenue Increase Reserve and (ii) file a study on the appropriate policy for revenue recognition (the "Revenue Recognition Study"). The Revenue Recognition Study was originally ordered to be filed by March 31, 2000. This date was subsequently deferred pending resolution of the tax dispute between Newfoundland Power and the CRA. The Revenue Recognition Study is filed with this application as Exhibit NP-3.

3 See p. 3 in Exhibit NP-3.

4 See pp. 12 and 13 of the report of JT Browne Consulting.

Table 2 sets out, for 2006 to 2008, the *pro forma* revenue impact of Newfoundland Power's proposed adoption of the Accrual Method of revenue recognition for regulatory purposes in 2006.

Table 2
***Pro Forma* Revenue Impact**
Accrual Method
2006 to 2008
(000s)

	2006	**2007**	**2008**
Revenue Increase	$457	$215	$262

The $457,000 *pro forma* increase in 2006 revenue in Table 2 represents approximately 0.1% of forecast revenue for that year.[5] The change in the magnitude of *pro forma* impacts from year to year primarily reflects forecast energy sales growth.[6] These relatively small annual differences reflect the fact that both the Billed Method and Accrual Method each recognize 12 months of revenue for each year.

3.1.4 Policy Proposal

Newfoundland Power is proposing to adopt the Accrual Method of revenue recognition for regulatory purposes commencing in 2006. This proposal will make the Company's policy for revenue recognition consistent with established regulatory principles, GAAP and Canadian public utility practice.

5 $457,000 ÷ $417,069,000 (2006 forecast billed revenue) = 0.11%. See Exhibit NP-14, page 1 of 5, line 1.
6 Based on the Company's customer and energy sales forecast of March 31, 2005.

3.2 Transitional Issues

Newfoundland Power's proposed adoption of the Accrual Method of revenue recognition for regulatory purposes in 2006 will require the Board to address certain transitional accounting issues.

These issues include accounting for the 2005 Unbilled Revenue; recognition of approximately $9.6 million of 2005 Unbilled Revenue in 2006 to offset rising depreciation expense; disposition of the Unbilled Revenue Increase Reserve; and treatment of rate base through a transition period.

This section of evidence addresses these 4 transitional issues.

3.2.1 2005 Unbilled Revenue

Exhibit NP-4 shows the calculation of the forecast 2005 Unbilled Revenue of $24.3 million.

Under the Billed Method, the forecast 2005 Unbilled Revenue of $24.3 million would be recognized by Newfoundland Power in January 2006. Under the Accrual Method, the $24.3 million would be recognized by Newfoundland Power in December 2005. In either case, the actual cash received by Newfoundland Power is the same. Accordingly, the 2005 Unbilled Revenue represents an accounting accrual as opposed to cash revenue.

For financial reporting purposes, the 2005 Unbilled Revenue will be reported as both an asset and a liability in Newfoundland Power's balance sheets as of December 31, 2005.[7]

The asset value of unbilled revenue will be reported on the Company's balance sheets as part of *accounts receivable*. This reflects the GAAP requirement to report the unbilled revenue at

[7] This is the result of recent CICA pronouncements referred to on p. 2 in Exhibit NP-3 and on pp. 6 and 7 of the report of JT Browne Consulting.

December 31 in each year as an amount due to Newfoundland Power for service delivered to its customers by that date.

The liability value of the 2005 Unbilled Revenue will be reported on the Company's balance sheet as part of *other liabilities*. This reflects the fact that, as at year-end, the 2005 Unbilled Revenue is, in effect, an amount that will be recognized by the Company in future accounting periods as determined by the Board.[8]

Recognition of the 2005 Unbilled Revenue for regulatory purposes is the principal transitional issue arising from Newfoundland Power's proposed adoption of the Accrual Method of revenue recognition in 2006.

Given the magnitude and non-cash nature of the 2005 Unbilled Revenue, Newfoundland Power proposes it be recognized on a prospective basis over a period of years (the "Transition Period"). In considering the length of the Transition Period, two essential issues must be balanced.

Firstly, the 2005 Unbilled Revenue can serve to offset future revenue that would otherwise be required from Newfoundland Power's customers through rates. Secondly, because recognition of the 2005 Unbilled Revenue does not provide additional cash, the amount that can be recognized in any single year is limited by the need to maintain Newfoundland Power's financial integrity.

[8] This liability value will be reduced as and when portions of the 2005 Unbilled Revenue are approved by the Board to be recognized and reported as revenue in Newfoundland Power's statement of earnings. The liability balance that remains unrecognized is referred to in this evidence as the "unrecognized" 2005 Unbilled Revenue.

3.2.2 2006 Depreciation Expense

Newfoundland Power's annual depreciation expense is based upon depreciation rates and periodic true-up adjustments approved by Board Orders. Depreciation expense is a cost of providing service that is fully recoverable from customers.

Depreciation expense for 2006 is forecast to increase by $6,950,000 over 2005. Exhibit NP-5 shows forecast depreciation expense for 2005 and 2006.

Table 3 summarizes the forecast increase in Newfoundland Power's depreciation expense in 2006.

Table 3
Forecast 2006 Depreciation Expense
(000s)

Forecast 2005 Depreciation Expense	$32,129
2006 Increases	
Conclusion of True-up Adjustment	5,793
Impact of Increased Plant Investment	1,157
Total of 2006 Increases	6,950
Forecast 2006 Depreciation Expense	$39,079

The increase primarily results from the conclusion of a true-up adjustment but also reflects forecast increases in plant investment to December 31, 2006.

The true-up adjustment was proposed by Newfoundland Power in 2003 and ordered by the Board based on a 2002 depreciation study completed by Gannett Fleming Inc. ("Gannett Fleming"). Gannett Fleming calculated an accumulated depreciation reserve variance of $17.2 million as of

December 31, 2001. The depreciation reserve variance in excess of 5 per cent is being amortized, as a true-up adjustment, equally over 2003, 2004, and 2005.[9] This amortization reduced depreciation expense in these years and has resulted in lower rates for Newfoundland Power's customers.[10]

A review of the accumulated depreciation reserve by Gannett Fleming as of December 31, 2004 has confirmed, subject to completion of the next detailed depreciation study in 2006[11], that the accumulated depreciation reserve variance that existed when the 2002 depreciation study was completed will effectively be amortized as of December 31, 2005.

Plant investment is forecast to increase from December 31, 2005 to December 31, 2006 by approximately $37 million.[12] Depreciation expense, based on increased plant investment and depreciation rates approved by the Board in Order No. P.U. 19 (2003), is forecast to increase from $37,922,000[13] in 2005 to $39,079,000 in 2006; an increase of $1,157,000.

Conclusion of the true-up adjustment as of December 31, 2005 combined with increased plant investment in 2006 results in a total forecast increase in depreciation expense from 2005 to 2006 of $6,950,000.

---

9 The three year annual true-up adjustment of $5,793,000 was approved by the Board in Order No. P.U. 19 (2003).

10 The forecast reduction in depreciation expense for 2003 and 2004 was $5,793,000 in each year. Related tax effects for 2003 and 2004 were $3,402,000 and $3,119,000 respectively. Total reduction in revenue required from customer rates was $9,195,000 in 2003 and $8,912,000 in 2004.

11 Based on plant in service as of December 31, 2005.

12 Based on forecast plant investment for 2005 and 2006 provided in Exhibit NP-11.

13 Gross depreciation expense (before the true-up adjustment) as per Exhibit NP-5, line 11.

The 2005 Unbilled Revenue can be used to offset:

(i) the forecast increase in depreciation expense from 2005 to 2006 of $6,950,000; and

(ii) the forecast 2006 income tax effects of $3,086,000[14] related to the transition from the Billed Method to the Accrual Method of revenue recognition for income tax purposes.

To offset these amounts, which total $10,036,000, would require that $9,579,000 of the 2005 Unbilled Revenue be recognized for regulatory purposes in 2006.[15] Alternatively, approximately $15.7 million in cash revenue from customers through rates would otherwise be required to offset increased 2006 depreciation expense, associated tax effects, and 2006 tax obligations arising from the Tax Settlement. This is a reflection of the tax effects described earlier under section ***2.2.3 Income Tax Effects of the Tax Settlement***.

The recognition of 2005 Unbilled Revenue to offset increased depreciation expense effectively results in the substitution of one accounting accrual for another. The depreciation true-up adjustments and unbilled revenue accruals are similar in that both are non-cash accounting accruals that reduce the revenue that would otherwise be required from customers through rates. A comparison of the alternatives of using the unbilled revenue versus cash revenue to recover increasing 2006 depreciation expense is set out in Exhibit NP-6.

---

[14] The forecast 2006 income tax effects are limited to the amount determined by the Tax Settlement. See Section ***2.2.3 Income Tax Effects of the Tax Settlement***.

[15] 2005 Unbilled Revenue of $9,579,000 in addition to the *pro forma* revenue change of $457,000 (see Table 2) equals $10,036,000.

Cash flow and cash flow metrics are measures used by investors and credit analysts to assess the overall creditworthiness of Newfoundland Power. Therefore, Newfoundland Power's recognition of the 2005 Unbilled Revenue in any year will practically be limited by the resulting cash flow impacts. The Company's proposal to recognize the 2005 Unbilled Revenue over a Transition Period reflects this limitation. Under Newfoundland Power's proposal, non-cash revenue is being used to offset an increase in non-cash expense (i.e., depreciation). This effectively limits the cash flow impacts.

3.2.3 The Unbilled Revenue Increase Reserve

In Order No. P.U. 36 (1998-99), the Board ordered Newfoundland Power to establish an Unbilled Revenue Increase Reserve (the "Reserve").

The Reserve was established to account for the impact of the revenue recovery lag inherent between the Billed Method and Accrual Method of revenue recognition when customer electricity rates change.

In Order No. P.U. 36 (1998-99), the Board ordered that disposition of the Reserve would be dealt with in the future order arising from the review of Newfoundland Power's revenue recognition policy.

Currently, a balance of $295,000 exists in the Reserve. Exhibit NP-7 shows the historical development of the current balance in the Reserve. Conceptually, this balance represents an amount due from customers which has not yet been billed.

Should the Board approve Newfoundland Power's proposal to adopt the Accrual Method of revenue recognition for regulatory purposes commencing in 2006, the Reserve is expected to have limited, if any, future application.[16] Netting the Reserve balance to reduce the unrecognized 2005 Unbilled Revenue will eliminate the amount due from customers without affecting customer rates.

3.2.4 Rate Base and the Transition Period

Maintaining an appropriate accounting relationship between Newfoundland Power's revenue and returns over the Transition Period requires that the accounting treatment of the unrecognized 2005 Unbilled Revenue for regulatory purposes be addressed.

The unrecognized 2005 Unbilled Revenue is revenue for which recognition has been deferred until future accounting periods (i.e., it is a deferred liability). The Board currently includes deferred assets, such as the balance in Newfoundland Power's Weather Normalization Reserve, and deferred liabilities, such as deferred income taxes, in the computation of Newfoundland Power's rate base. Deferred income taxes, for example, are deducted from the Company's rate base. Conceptually, there is no difference between deferred income taxes and the deferred liability related to the 2005 Unbilled Revenue.

Newfoundland Power proposes that the average value of the unrecognized 2005 Unbilled Revenue, reported in the Company's balance sheets as *other liabilities,* be deducted from rate base commencing in 2006 until the Transition Period is complete.

[16] The Reserve was created in conjunction with a February 1st, 1999 rate change. Subsequent allocations in 2000, 2002 and 2005 arose from January 1st rate changes arising from operation of the automatic adjustment formula.

The appropriateness of this approach is addressed in the report of JT Browne Consulting filed with this Application.[17]

Exhibit NP-8 shows the *pro forma* effects of reducing rate base by the average value of the unrecognized 2005 Unbilled Revenue through the Transition Period.[18]

Table 4 summarizes these *pro forma* rate base effects.

Table 4
***Pro Forma* Rate Base Effects[19]**
2006 to 2009
(000s)

	2006	**2007**	**2008**	**2009**
Existing Methodology	$763,651	$781,325	$800,390	$813,989
Transitional Adjustment	(19,325)	(10,791)	(3,597)	-
Proposed Methodology	$744,326	$770,534	$796,793	$813,989

After the Transition Period, no adjustments to rate base will be required as a result of the 2005 Unbilled Revenue.

3.2.5 Transitional Proposals

In this Application, Newfoundland Power is proposing that the forecast 2005 Unbilled Revenue of $24.3 million be dealt with over the Transition Period as follows:

17 See pp. 23 and 24 of the report of JT Browne Consulting.
18 For the purpose of this illustration, a transition period of three years (2006-2008) was assumed. The actual length of the transition period will be subject to further application by Newfoundland Power and future determination by the Board.
19 See Exhibit NP-8 for assumptions and details for the *pro forma* calculations.

1. the amount of $9,579,000 be recognized in 2006 as described in Section ***3.2.2 2006 Depreciation Expense***;

2. the amount of $295,000 be applied to reduce the unrecognized 2005 Unbilled Revenue in 2006 as described in Section ***3.2.3 The Unbilled Revenue Increase Reserve***; and

3. disposition of the forecast remaining unrecognized 2005 Unbilled Revenue of $14,388,400 (i.e., the forecast unrecognized 2005 Unbilled Revenue at year-end 2006) be determined by the Board in a future order.

In addition, Newfoundland Power proposes that, commencing in 2006, the average value of the unrecognized 2005 Unbilled Revenue, reported in the Company's balance sheets as *other liabilities,* be deducted from rate base as described in section ***3.2.4 Rate Base and the Transition Period***.

Given the magnitude and nature of the 2005 Unbilled Revenue, dealing with it over a Transition Period is a reasonable balance of the interests of Newfoundland Power and its customers. As well, this will ensure that the Board maintains continuing supervision of the disposition of the 2005 Unbilled Revenue.

Recognizing $9,579,000 of the 2005 Unbilled Revenue in 2006 will permit recovery of increasing depreciation expense and forecast income tax effects. This will defer a rate increase for Newfoundland Power's customers in 2006.

Applying the current Reserve balance to reduce the unrecognized 2005 Unbilled Revenue is appropriate since the Reserve balance has already been recognized as revenue. This approach allows the Company to address the outstanding balance in the Reserve without affecting customer rates.

The proposed reduction in rate base is consistent with, and conceptually similar to, the Board approved treatment of other deferred assets, such as the Weather Normalization Reserve, and deferred liabilities, such as deferred income tax, in the determination of Newfoundland Power's rate base. This proposal will ensure the maintenance of an appropriate accounting relationship between revenue and returns.

3.3 Consequential Matters

This Application provides an appropriate context for the Board to consider two consequential matters.

Moving to the Accrual Method of revenue recognition will facilitate the adoption of the Asset Rate Base Method.

Consideration of forecast values for invested capital and rate base to include in the Automatic Adjustment Formula for 2006 is appropriate at this time.

3.3.1 Asset Rate Base Method ("ARBM")

In Order No. P.U. 19 (2003), the Board decided that the ARBM should replace the current method used by Newfoundland Power to calculate return on rate base. In addition, Newfoundland Power was ordered to review the matter of adoption of the ARBM and the remaining reconciling items between invested capital and rate base identified by the Board's Financial Consultant.

The Asset Rate Base Method Review is Exhibit NP-9.

Working Capital Difference

The difference between the working capital included in invested capital and the working capital included in rate base is currently the largest reconciling item between Newfoundland Power's invested capital and rate base identified by the Board's Financial Consultant.[20]

The working capital included in invested capital is a balance sheet calculation of the difference between current assets and current liabilities as at December 31. The working capital included in rate base is an allowance based upon a study that examines timing differences between receipt of revenue and payment of expenses[21].

Exhibit NP-10 sets out the forecast working capital difference between invested capital and rate base for 2006 based upon new reporting requirements introduced by the CICA in 2005.[22]

The 2006 forecast working capital difference between rate base and invested capital of $465,000 is a substantial reduction from previous reconciliations.[23] This is largely because accounts receivable associated with unbilled revenue as at December 31 of each year will be reflected in the Company's balance sheets as a current asset. The corresponding regulatory liability (i.e., the

---

20 Newfoundland Power 2003 General Rate Application, Grant Thornton, Supplementary Evidence, April 4, 2003, Exhibit II.

21 Commonly referred to as a lead/lag study.

22 See Exhibit NP-9, page 5 of 9, **3.1 Working Capital**.

23 In Newfoundland Power's 2003 General Rate Application, this forecast difference was ($20,957,000) for 2004 – Grant Thornton, Supplementary Evidence, April 4, 2003, Exhibit II.

unrecognized 2005 Unbilled Revenue), however, is subject to Board determination and therefore not recorded as a current liability.

There will always be a difference between working capital included in invested capital and that included in rate base because of the different methodologies which underlie the calculations. However, with the accrual of the approximately $24.3 million of 2005 Unbilled Revenue, the working capital component of invested capital will more closely mirror the working capital component of rate base.

Other Reconciling Items

The Company proposes to discontinue the use of regulated common equity in the calculation of return on rate base in 2006. In its place, Newfoundland Power will use book common equity. Book common equity reflects actual equity investment used to finance rate base.

Use of regulated common equity is essentially a legacy issue for Newfoundland Power and there appears to be no regulatory policy justification for its continued use.[24] This will eliminate the second largest reconciling item identified by the Board's Financial Consultant.[25]

The corporate income tax deposit was refunded to the Company by the CRA in 2005. As a result, this reconciling item no longer exists. This was the third largest reconciling item identified by the Board's Financial Consultant.

[24] See Section 2.6 of Exhibit NP-9.
[25] See Table 1 of Exhibit NP-9.

Overall Approach to ARBM Adoption

The first step in the adoption of the ARBM was completed with the inclusion of deferred charges in rate base as ordered in Order No. P.U. 19 (2003).

Conceptually, invested capital and rate base should be equivalent. Elimination of the three largest reconciling items will substantially reduce the difference between rate base and invested capital. This will add transparency to the relationship between invested capital and rate base. However, practically there will always be some differences.[26]

The *pro forma* differences between invested capital and rate base for 2006 to 2009 are set out in Exhibit NP-9, page 8, Table 4.

Newfoundland Power will file its next general rate application based upon the ARBM. The remaining reconciling items (which should be relatively small) can be considered at that proceeding.

3.3.2 2006 Formula Operation

Automatic Adjustment Formula (the "Formula")

In Order Nos. P.U. 16 (1998-99), P.U. 36 (1998-99) and P.U. 19 (2003), the Board established the Formula to set an appropriate rate of return on rate base for Newfoundland Power on an annual basis. The Formula adjusts Newfoundland Power's rate of return annually based upon

[26] These include differences related to the calculation of working capital and other differences such as construction work in progress. For example, construction work in progress will be reflected in invested capital (because the money has been invested) but not in rate base (because the asset being constructed is not yet "used and useful").

changes in the forecast cost of common equity. The forecast cost of common equity is based upon changes in long term Government of Canada Bond yields.

Under the Board's current practice, the forecast values for invested capital and rate base used in the Formula are considered by the Board through the annual capital budget approval process.

In this Application, due to the Company's proposals associated with adopting the Accrual Method of revenue recognition, consideration must be given to these 2006 forecast values for use in the Formula for the calculation of Newfoundland Power's rate of return on rate base for 2006.

No changes to the Formula itself are proposed in this Application.

2006 Rate Base and Invested Capital

Newfoundland Power's forecast average rate base for 2006, which incorporates the proposals made in this Application, is $744,326,000.

The detailed calculation of Newfoundland Power's forecast average rate base for 2005 and 2006 is shown in Exhibit NP-11.

Newfoundland Power's forecast average invested capital for 2006, which incorporates the proposals made in this Application, is $745,752,000.

The detailed calculation of Newfoundland Power's forecast average invested capital for 2005 and 2006 is shown in Exhibit NP-12.

Pro Forma 2006 Formula Operation

The *pro forma* operation of the Formula for 2006 is shown in Exhibit NP-13.

3.3.3 Consequential Proposals

In this Application, Newfoundland Power is proposing:

1. to use book common equity in the calculation of rate of return on rate base commencing in 2006; and

2. forecast 2006 values for rate base of $744,326,000 and invested capital of $745,752,000 be approved for use in the Formula for the calculation of Newfoundland Power's rate of return on rate base for 2006.

The reduction in the working capital difference, together with the use of book common equity instead of regulated common equity, and the elimination of the corporate income tax deposit, will significantly reduce the difference between rate base and invested capital beginning in 2006. This will mark significant progress in Newfoundland Power's adoption of the ARBM for calculating its return on rate base. It will also facilitate the filing of Newfoundland Power's next general rate application using the ARBM.

3.4 Summary of Proposals

This section of evidence summarizes the proposals contained in the Application and indicates the forecast effects of these proposals in 2006.

3.4.1 The Proposals

In this Application, Newfoundland Power is proposing:

1. to change its accounting policy for revenue recognition for regulatory purposes to the Accrual Method commencing in 2006;

2. that the 2005 Unbilled Revenue be dealt with on a prospective basis over a Transition Period commencing in 2006;

3. to recognize for regulatory purposes in 2006, $9,579,000 of the 2005 Unbilled Revenue to recover forecast increased depreciation expense in 2006 and forecast income tax effects;

4. to apply the current balance of $295,000 in the Unbilled Revenue Increase Reserve to reduce the unrecognized 2005 Unbilled Revenue in 2006;

5. that the disposition of the forecast remaining unrecognized 2005 Unbilled Revenue of $14,388,400 (i.e., the forecast unrecognized 2005 Unbilled Revenue at year-end 2006) be determined by the Board in a future order;

6. to deduct the average value of the unrecognized 2005 Unbilled Revenue from rate base commencing in 2006;

7. to use book common equity in the calculation of rate of return on rate base commencing in 2006; and

8. that forecast 2006 values for rate base of $744,326,000 and invested capital of $745,752,000 be approved for use in the Formula for the calculation of Newfoundland Power's rate of return on rate base for 2006.

3.4.2 Forecast Effects of Proposals

Exhibit NP-14 is the forecast financial statements for Newfoundland Power for 2005 and 2006 incorporating the proposals made in the Application.

Exhibit NP-15 summarizes the Company's 2006 forecast financial results before and after incorporating the proposals made in this Application. Exhibit NP-15 shows Newfoundland Power's forecast rate of return on rate base for 2006, before incorporating the proposals made in the Application, of 7.02%. This is below the existing range of rate of return on rate base of 8.50% to 8.86%.

The proposals made in this Application will, if approved by the Board, permit Newfoundland Power a reasonable opportunity to earn a just and reasonable return on rate base in 2006.

Tax Settlement between Newfoundland Power Inc. and Minister of National Revenue

Dated
June 1, 2005

OUT OF COURT SETTLEMENT
pursuant to subsection 169(3)
of the *Income Tax Act*

BETWEEN:

NEWFOUNDLAND POWER INC.

and

MINISTER OF NATIONAL REVENUE

WHEREAS Newfoundland Power Inc. has appealed to the Tax Court of Canada in file bearing nº 2003-39(IT)G regarding its 1992 and 1993 taxation years and in file bearing nº 2003-42(IT)G regarding its 1994, 1995, 1996, 1997, 1998 and 1999 taxation years.

WHEREAS the parties have reached the conclusion that it is in the best interest of both parties that these appeals be settled.

THE ISSUES INVOLVED:

The 1992 taxation year

1. The only issue concerns the loss resulting from the sale of the Carbonear property which Newfoundland Power Inc. (referred to as NLP in this agreement) deducted as a current business expense while the Minister of National Revenue (referred to as the Minister in this agreement) considered the loss as a capital loss resulting in an allowable capital loss of $27,245. available as a deduction against capital gains in future years.

2. Therefore by a Notice of Reassessment dated May 18, 2000 the Minister added an amount of $36,327. in the computation of the

taxable income of NLP on the basis that this amount represented a deduction attributable to the sale of a property (the Carbonear property) which deduction could not be allowed as a current expense deduction in the computation of the said income.

The 1993 taxation year

3. There are two issues closely linked together namely the use of the accrual method of accounting and the adjustments made or not made for the 1993 taxation year concerning the unbilled income.

4. By a Notice of Reassessment dated August 2, 2000 for the 1993 taxation year the Minister added an amount of $16,855,307. to the income of NLP on the basis that the said amount represented the December 1993 unbilled income (originally included by NLP in its 1994 taxation year) which had to be included in the computation of taxable income in 1993 based on the application of the accrual method of accounting.

5. In issuing the Notice of Reassessment dated August 2, 2000 for the 1993 taxation year the Minister did not exclude (deduct) in the computation of income for 1993 the amount resulting from the amount of $17,977,458. of unbilled income for the month of December 1992 which was billed, paid and originally included by NLP in the computation of its 1993 taxable income.

The 1994, 1995, 1996, 1997, 1998 and 1999 taxation years

6. The only issue is the use or application of the accrual method of accounting for the computation of NLP's taxable income for each year. The amount (quantum) of the adjustments for each year is not in dispute.

7. In issuing the Notices of Reassessments dated March 13, 2001 for each of the 1994, 1995, 1996, 1997, 1998 and 1999 taxation years the Minister made the followings adjustments:

- For 1994: decreased NLP's income by an amount of $309,149.
- For 1995: increased NLP's income by an amount of $483,745.
- For 1996: decreased NLP's income by an amount of $528,126.
- For 1997: increased NLP's income by an amount of $143,939.
- For 1998: decreased NLP's income by an amount of $317,434.
- For 1999: increased NLP's income by an amount of $416,386.

THE PARTIES HEREBY AGREE AS FOLLOWS:

8. Newfoundland Power Inc. has represented and agreed that commencing with the 2006 taxation year and afterwards, NLP will compute its income for tax purposes based upon the accrual accounting method for the period of January 1 to December 31.

9. Newfoundland Power Inc. has also represented and agreed that it will include a third of the unbilled revenue outstanding as at December 31, 2005 (which is currently estimated at $23,510,000. but could differ) in the computation of its income for each of its 2006, 2007 and 2008 taxation years.

10. As appears from the terms of this agreement, the Minister of National revenue shall execute all of his obligations upon signing of this agreement while all of NLP's obligations are undertaken on a purely prospective basis except for the notices of discontinuance.

11. As an important and symbolic gesture to mark NLP's profound commitment that it will fulfill its obligations set forth in paragraphs 8 and 9 of this agreement, NLP accepts to provide within the next fifteen (15) working days , waivers for each of the

2000 to 2004 taxation years which is suggested will read as follows:

" The waiver is given in respect of Newfoundland Power Inc. taxable income for the year limited to the application of the accrual method of accounting and also the inclusion of the December unbilled revenue."

12. In consideration of the obligations undertaken by NLP, the Minister of National Revenue will issue a notice of reassessment for the 1992 taxation year whereby the Minister will allow the amount of $36,327. (as it was originally claimed) as a current expense deductible in the computation in the taxable income of NLP.

13. In consideration of the obligations undertaken by NLP, the Minister of National Revenue will cancel the above mentioned notices of reassessments and will issue new notices of reassessment for each of the 1993 to 1999 taxation years in order to eliminate all adjustments previously made by reason of the application of the accrual accounting method :

- For the 1993 taxation year :

  The Minister will decrease by an amount of $16,855,307. NLP's taxable income for said year.

- For the 1994 taxation year :

  The Minister will increase by an amount of $309,149. NLP's taxable income for said year

- For the 1995 taxation year:

  The Minister will decrease by an amount of $483,745. NLP's taxable income for said year

- For the 1996 taxation year:

  The Minister will increase by an amount of $528,126. NLP's taxable income for said year

- For the 1997 taxation year:

  The Minister will decrease by an amount of $143,939. NLP's taxable income for said year

- For the 1998 taxation year:

  The Minister will increase by an amount of $317,434. NLP's taxable income for said year

- For the 1999 taxation year:

  The Minister will decrease by an amount of $416,386. NLP's taxable income for said year

14. Upon signing this agreement Newfoundland Power Inc. shall provide to the Minister of National Revenue's counsel duly signed Notices of Discontinuance for both appeals currently before the Tax Court of Canada.

15. The Notice of Discontinuance herein mentioned will be held in trust by the Minister of National Revenue's counsel who undertakes not to file it with the Tax Court of Canada until the reassessments mentioned in this agreement have been issued by the Minister of National Revenue.

16. Newfoundland Power Inc. waives its right of objection or appeal from the reassessments envisaged by this agreement for the 1992

to 1999 taxation years, in accordance with subsections 165(1.2) and 169(2.2) of the *Income Tax Act.*

17. Any refund resulting from the issuance of new notices of reassessments for the 1992 to 1999 taxation years will be determined in accordance with the provisions of the Income Tax Act.

CONCLUSION

18. Upon either party not conforming with one or more of the conditions set out in this agreement, the latter shall be deemed null and void.

19. Each party assumes its own costs.

MONTREAL, JUNE 1st, 2005

Per: ______________________
Guy A. Gagnon
Counsel for the Appellant

MONTREAL, May 31, 2005

JOHN H. SIMS QC
Deputy Attorney General of Canada
Solicitor for the Respondent

Per: ______________________
Daniel Marecki
Counsel

Newfoundland Power Inc.

***Pro Forma* Income Tax Effects**
2006 - 2008
(000s)

		2005	2006	2007	2008
1	Unbilled Revenue - Current Year[1]	$ 24,262 [2]	$ 24,719	$ 24,934	$ 25,196
2					
3	Reversal of Unbilled Revenue - Previous Year		(24,262)	(24,719)	(24,934)
4					
5	Increase in Unbilled Revenue		457	215	262
6					
7	Recognition of 2005 Unbilled Revenue[3]		8,087	8,087	8,087
8					
9	Unbilled Revenue Recognized for Income Tax Purposes[4]		$ 8,544	$ 8,302	$ 8,349
10					
11	Tax Rate[5]		36.12%	36.12%	36.12%
12					
13	Income Tax Effects		$ 3,086	$ 2,999	$ 3,016

Notes:

[1] Estimated unbilled revenue as of December 31[st] each year based on the Company's customer and energy sales forecast dated March 31, 2005 and currently approved rates.

[2] A detailed calculation of the forecast 2005 Unbilled Revenue is set out in Exhibit NP-4.

[3] The amount of forecast 2005 Unbilled Revenue to be recognized as revenue for income tax purposes in equal amounts over three years beginning in 2006 in accordance with the Tax Settlement. ($24,262,400/3 = $8,087,467)

[4] Total estimated amount of unbilled revenue to be recognized in the year as revenue for income tax purposes in accordance with the Tax Settlement.

[5] Newfoundland Power's forecast marginal income tax rate is 36.12%.

Revenue Recognition Study
(filed in compliance with Order Nos. P.U. 36 (1998-99), P.U. 28 (1999-2000) and P.U. 19 (2003))

September 2005

Table of Contents

A. INTRODUCTION

For financial reporting, regulatory and income tax purposes, Newfoundland Power has always recognized electricity revenue as its customers are billed for the electrical service they receive (the "Billed Method").

In Newfoundland Power's general rate proceedings to establish electricity rates for 1999 and for 2003/2004, the appropriateness of the continued use of the Billed Method for revenue recognition was raised. In Order No. P.U. 36 (1998-1999), the Board ordered Newfoundland Power to:

> *"…commission a study on the appropriate basis of recognizing revenue. The study shall provide an updated survey on revenue recognition policies of Canadian gas and electric utilities, the full implications of changing the revenue recognition policy on both financial reporting and revenue requirement, the accounting treatment applied by other Canadian gas and electric utilities which changed their revenue recognition policy, and the recommendations of the company. This study shall be filed with the Board before the next general rate application or by March 31, 2000, whichever is earlier."* (the "Revenue Recognition Study").

In Order Nos. P.U. 28 (1999-2000) and P.U. 19 (2003), the filing date of the Revenue Recognition Study was deferred pending settlement of an outstanding tax dispute (the "Tax Settlement") between Newfoundland Power and the Canada Revenue Agency (the "CRA"). A primary issue of the tax dispute was the use of the Billed Method of revenue recognition for tax purposes. The Tax Settlement was reached in June 2005.

B. REVENUE RECOGNITION

B.1 Accrual Method vs. Billed Method – Underlying Methodology

Under the accrual method of revenue recognition, electricity revenue is recognized as electrical service is delivered to customers (the "Accrual Method"). Revenue is effectively recognized in the period in which it is earned rather than, as under the Billed Method, in the period in which it is billed.

Newfoundland Power's aggregate electricity billings to its customers at any point in time will lag the value of aggregate electrical service deliveries by approximately ½ month.[1] Under the Billed Method, this means that the value of electrical service delivered to customers in December but billed in January of the following year (the "Unbilled Revenue") is not recognized as revenue until it is billed. Under the Accrual Method, this Unbilled Revenue would be "accrued" and recognized as revenue in December.

[1] This lag was recognized by the Board in Order No. P.U. 36 (1998-99) at pp. 90 *et. seq.* and Order No. P.U. 19 (2003) at pp. 86 *et. seq.*

B.2 Canadian Standards and Practice

B.2.1 Financial Reporting

Canadian generally accepted accounting principles ("GAAP") with respect to revenue recognition for financial reporting purposes are set out in section 3400 of the Canadian Institute of Chartered Accountants ("CICA") Handbook. Pursuant to section 3400, revenue would normally be recognized under the Accrual Method for financial reporting purposes.

Section 1100 of the CICA Handbook effectively permits rate-regulated entities such as Newfoundland Power to recognize revenue under methods other than the Accrual Method. For this reason, Newfoundland Power's use of the Billed Method is in compliance with GAAP.

The recent CICA accounting guideline, AcG-19,[2] effectively requires rate-regulated entities like Newfoundland Power to record regulatory assets and liabilities[3] on their balance sheet. AcG-19 is effective for fiscal years ending on or after December 31, 2005.

To comply with AcG-19, Newfoundland Power will be required to report Unbilled Revenue on its December 31, 2005 balance sheet separately as (i) accounts receivable and (ii) a corresponding regulatory liability.[4] Newfoundland Power's forecast Unbilled Revenue at December 31, 2005 is $24,262,400.

AcG-19 does not require Newfoundland Power to recognize the forecast regulatory liability of $24,262,400 as revenue. It therefore does not require a change in Newfoundland Power's revenue recognition policy or affect its statement of earnings.

The CICA's review of accounting issues surrounding the financial reporting by rate-regulated entities is still ongoing. A key issue under consideration is whether utilities will, in effect, continue to be allowed to recognize revenue and expenses for financial reporting purposes in a manner that is different from that required to be followed by entities not subject to rate regulation.

---

[2] CICA accounting guidelines are a component of the CICA Handbook and are therefore a source of GAAP. Accounting guideline ACG-19 titled *disclosures by entities subject to rate regulation* was issued in May 2005.

[3] Regulatory assets and liabilities are created when regulators require revenues and/or expenses to be recognized in a manner other than that normally required by GAAP. Regulatory assets are amounts expected to be recovered from customers in future periods through the ratemaking process. Regulatory liabilities are amounts expected to be refunded or applied for the benefit of customers in future periods through the ratemaking process.

[4] This differs from previous disclosure of the asset and regulatory liability associated with unbilled revenue whereby the two were netted and effectively excluded from Newfoundland Power's balance sheet for reporting purposes. AcG-19 addresses only disclosure issues. It does not address recognition or measurement issues associated with accounting for rate-regulated operations, and therefore has no impact on Newfoundland Power's Statement of Earnings or its policy with respect to revenue recognition.

B.2.2 Income Tax

The CRA's position in the tax dispute was that, under provisions of the Income Tax Act (Canada), electricity revenue is required to be recognized under the Accrual Method for income tax purposes. Pursuant to the Tax Settlement, Newfoundland Power will begin using the Accrual Method of revenue recognition on a prospective basis for the calculation of income tax commencing in 2006.

As a transitional matter, the Unbilled Revenue as of December 31, 2005 will be recognized as revenue for income tax purposes in equal amounts over a three-year period beginning in 2006. Further details with respect to the Tax Settlement and the related transitional matters are provided in section C.3 of this study.

Adoption of the Accrual Method for regulatory purposes on a prospective basis would enhance regulatory transparency by ensuring a consistent matching of recognized revenue and associated income tax expense.

B.2.3 Regulatory Practice

The Company surveyed the 27 Canadian utilities listed in Appendix A with respect to their revenue recognition policy for regulatory purposes. 23 utilities responded to the survey. All respondents use the Accrual Method of revenue recognition for regulatory purposes.[5] Further details with respect to regulatory practice and the related transitional matters are provided in section C.3 of this study.

The use of the Accrual Method will move Newfoundland Power's revenue recognition policy into the mainstream of Canadian public utility practice.

C. IMPACT OF ADOPTING THE ACCRUAL METHOD

C.1 Impact on Revenue Generally

Under the Accrual Method of revenue recognition, Unbilled Revenue would be recognized in December. Under the Billed Method, this revenue is recognized when billed in January of the following year.

Newfoundland Power's *pro forma* Unbilled Revenue as at December 31, 2005 through 2008 is set out in Table 1.

[5] As evidenced by the notes to their financial statements, all 27 of these utilities use the Accrual Method of revenue recognition for financial reporting purposes.

Table 1
***Pro Forma* Unbilled Revenue**
(000s)

	As at December 31			
	2005	**2006**	**2007**	**2008**
Unbilled Revenue, End of Prior Year		$24,262	$24,719	$24,934
Change in Unbilled Revenue During the Year[6]		457	215	262
Unbilled Revenue, End of Year[7]	$24,262[8]	$24,719	$24,934	$25,196

On a prospective basis, adoption of the Accrual Method affects only the **timing** of the recognition of Unbilled Revenue. The revenue impact in any year is equal to the difference between (i) Unbilled Revenue at the end of the year and (ii) Unbilled Revenue at the end of the prior year.

For example, as set out in Table 1 above, Unbilled Revenue is forecast to increase in 2006 by $457,000. Under the Accrual Method, this increase of $457,000 is recognized as revenue in 2006. Under the Billed Method, the $457,000 would be recognized as revenue when billed in 2007.

C.2 Regulatory Impact – Revenue Requirement

Revenue requirement in a year is equal to the sum of (i) return on rate base and (ii) expenses, including income tax expense.

C.2.1 Return on Rate Base

Once fully adopted (transitional impacts are addressed in Section C.3), the Accrual Method of revenue recognition will have no material impact on rate base or the return on rate base.

Rate Base
The accrual of Unbilled Revenue will result in a corresponding increase in customer accounts receivable reflected on Newfoundland Power's balance sheet.

---

6 The *pro forma* change in Unbilled Revenue varies each year due primarily to forecast energy sales and differences in meter reading schedules.
7 Forecast electricity sales for December in each year (i) reflect normal temperatures for the periods and (ii) are based on the Company's customer and energy sales forecast dated March 31, 2005.
8 This is an estimate of the unbilled revenue at December 31, 2005. Actual unbilled revenue will be subject to year-end calculation.

In 2006, for example, a $457,000 increase in Unbilled Revenue, as shown in Table 1 above, will result in a $457,000 increase in accounts receivable on Newfoundland Power's balance sheet as at December 31, 2006.

However, accounts receivable is not a component of rate base. Rather, Newfoundland Power's rate base includes a cash working capital allowance ("CWC Allowance") that is calculated in accordance with a Board approved methodology[9].

The CWC Allowance is intended to reflect average daily working capital requirements that must be financed by the Company in providing service to customers. That requirement is driven by timing differences between when expenses are paid and when revenues are collected. When the payment of expenses precedes the collection of the related revenues, the cash to pay the expenses over the interim period must be financed.

The Accrual Method of revenue recognition has no impact on when and how (i) Newfoundland Power pays its expenses, (ii) Newfoundland Power bills its customers or (iii) customers pay their bills. It will therefore have no impact on Newfoundland Power's CWC Allowance and therefore no impact in its rate base.

Return on Rate Base
The Accrual Method of revenue recognition has no impact on the cost of debt and equity financing. Once fully adopted, it will therefore have no impact on the return on rate base.

C.2.2 Expenses, Including Income Taxes

The Accrual Method of revenue recognition has no impact on expenses required to provide service to customers, including income tax expense.

The income tax effects of the Accrual Method are illustrated in Table 2. The amounts shown in Table 2 are hypothetical.

9 Newfoundland Power's method for calculating the CWC Allowance to be included in rate base was approved in Order No. P.U. 37 (1984).

Table 2
Accrual Method vs. Billed Method
Illustration of Income Tax Expense
(000s)

	Accrual Method	Billed Method
Revenue Requirement	$50,000	$50,000
Revenue provided by:		
Billings	49,600[11]	50,000
Accrual of Unbilled Revenue[10]	400	-
Total revenue recognized for tax purposes	50,000	50,000
Total tax on revenue @ 36.12%	$18,060	$18,060

As illustrated in Table 2 above, the accrual and recognition of $400,000 of Unbilled Revenue under the Accrual Method effectively displaces the same amount of cash revenue that would otherwise be required from customers through rates. This is merely a timing difference because the $400,000 of revenue will not be available to reduce revenue required from rates in the following year. Under the Billed Method, the opposite is true. Either way, the total revenue recognized for income tax purposes is $50,000,000 and total income tax expense is $18,060,000.

The Accrual Method has no impact on the expense required to provide service to customers, including income tax expense. Therefore, it has no impact on this component of Newfoundland Power's revenue requirement.

C.3 Transitional Matters

C.3.1 The Transitional Amount

Adoption of the Accrual Method of revenue recognition for regulatory purposes commencing in 2006 will require Newfoundland Power and the Board to address the disposition of a regulatory

10 Under the Billed Method, this revenue would be recognized when billed in January of the following year.
11 $50,000,000 less $400,000 in unbilled revenue accrued in the previous year.

liability equal to the Unbilled Revenue that exists at the time of adoption.[12] Newfoundland Power's Unbilled Revenue is forecast to be $24,262,400 as at December 31, 2005.[13]

Additional unbilled revenue of $295,000 that is reflected in Newfoundland Power's Unbilled Revenue Increase Reserve (the "Reserve")[14] must also be addressed during the transition process.[15]

The purpose of the Reserve is to account for timing differences that arise during the month that rates change.

For example, rate changes are applied to electrical service **delivered** on and after the effective date of the new rates. However, the calculations underlying the new rates are based on electrical service **billed** on and after the effective date of the new rates. This creates a timing difference because Newfoundland Power's aggregate electricity billings at any point in time will lag its aggregate service deliveries by approximately ½ month. The Company uses the Reserve, in accordance with Board Orders, to recognize the revenue that is attributable to this timing difference.

If Newfoundland Power adopts the Accrual Method of revenue recognition for regulatory purposes, the Reserve is expected to have limited, if any, future application.

The $295,000 balance in the Reserve represents unbilled revenue that has already been recognized as revenue. The forecast 2005 Unbilled Revenue of $24,262,400 represents Unbilled Revenue that has not yet been recognized as revenue. It is therefore the net of these amounts, or $23,967,400, that is appropriate to be recognized as revenue under the Accrual Method (the forecast "Transitional Amount").

The forecast Transitional Amount is set out in Table 3.

---

12 The analysis that follows assumes that Newfoundland Power will adopt the Accrual Method of revenue recognition for regulatory purposes commencing in 2006. This coincides with the Tax Settlement and with the new CICA financial reporting pronouncements for disclosure of regulatory assets and liabilities.

13 As per Table 1 above.

14 In Order No. P.U. 36 (1998-1999), the Board ordered Newfoundland Power to establish an Unbilled Revenue Increase Reserve in connection with a February 1st, 1999 rate change. Subsequent allocations to the Reserve occurred in 2000, 2002 and 2005 in connection with January 1st rate changes arising from the operation of the automatic adjustment formula.

15 In Order No. P.U. 36 (1998-1999), the Board ordered that the disposition of the Reserve be dealt with in a future Order arising from the revenue recognition policy review.

Table 3
Forecast Transitional Amount
(000s)

Forecast 2005 Unbilled Revenue (Unbilled Revenue not yet recognized)	$24,262
Unbilled Revenue Increase Reserve Account (unbilled revenue already recognized)	(295)
Forecast Transitional Amount (Unbilled Revenue remaining to be recognized)	$23,967

C.3.2 The Transitional Approach

Recognizing the Transitional Amount as revenue on a prospective basis over a transition period will balance the interests of Newfoundland Power and its customers.

Transitional Approach for Tax Purposes
Pursuant to the Tax Settlement, Newfoundland Power will recognize the 2005 Unbilled Revenue as revenue for tax purposes in equal amounts over a three-year transition period commencing in 2006. Based on the forecast 2005 Unbilled Revenue of $24,262,400[16], this equates to recognizing $8,087,467 of the 2005 Unbilled Revenue for tax purposes in each of the years 2006, 2007 and 2008.

At a forecast marginal tax rate of 36.12%, Newfoundland Power will therefore record income tax expense with respect to this revenue in accordance with the Tax Settlement of $2,921,193[17] in each of the years 2006, 2007 and 2008.

Newfoundland Power will also record income tax in 2006, 2007 and 2008 on the incremental change in Unbilled Revenue in each of these years. For example, in 2006 the amount of Unbilled Revenue is forecast to increase by $457,000.[18] Income tax of $165,000[19] will be recorded on the incremental amount, resulting in total income tax of $3,086,193[20] to be recorded in 2006 as a result of the Tax Settlement.

---

16 As per Table 3 above.
17 ($24,262,400 / 3)* 0.3612
18 As per Table 1 above.
19 $457,000 * 0.3612
20 $2,921,193 + $165,000

Transitional Approach for Regulatory Purposes
For regulatory purposes, a change in accounting policy may be implemented on a prospective basis in the year of the change, or on a prospective basis over future accounting periods.

As set out in Appendix B, Newfoundland Power surveyed 27 Canadian utilities with respect to their adoption of the Accrual Method of revenue recognition for regulatory purposes. 13 of the 27 utilities have always recognized revenue using the Accrual Method.

Of the remaining 14 utilities surveyed, the transitional methodologies of five utilities were identified, as follows:

a) Two utilities accounted for the unbilled revenue existing at the date of transition retroactively as a direct adjustment to retained earnings.

   If Newfoundland Power were to account for the change in its revenue recognition policy in this manner, the effect would be to deny customers any benefit from recognition of the Transitional Amount.

b) Three utilities prospectively recognized their entire unbilled revenue as revenue in the year of transition.

Recognition of Unbilled Revenue does not increase Newfoundland Power's cash flows. Rather, the amount recognized effectively displaces cash revenue that would otherwise be provided by customers through rates. Cash flow and related metrics are crucial measures used by investors and credit analysts to assess the financial health of Newfoundland Power. Therefore, Newfoundland Power's recognition of Unbilled Revenue is limited by the resulting cash impacts and their effect on the Company's financial integrity.

In determining the appropriate transitional methodology for Newfoundland Power, the Board should consider the general principles to be used in the interpretation and application of the Public Utilities Act (the "Act"). These general principles were noted in the Supreme Court of Newfoundland, Court of Appeal Opinion on the Stated Case rendered on June 15, 1998.[21]

[21] The Court of Appeal at Paragraph 36, of the Opinion on the Stated Case indicated that, "In carrying out its functions under the Act, the Board is circumscribed by the requirement to balance the interests, as identified in the legislation, of the utility against those of the consuming public".

Recognizing the Transitional Amount as revenue on a prospective basis over a transition period will enable customers to receive benefit from the Transitional Amount in a manner which does not jeopardize Newfoundland Power's financial integrity. This approach is also consistent with past practice of the Board with respect to changes in accounting policy.[22]

C.3.3 Transitional Adjustment to Rate Base

Computation of Rate Base
As shown in Return 3 of Newfoundland Power's Annual Report to the Board of Commissioners' of Public Utilities, Newfoundland Power's rate base is comprised of:

a) the average investment in plant and equipment required to provide service to customers and approved by the Board as a result of the Company's annual capital budget applications;

b) the average of amounts owed to or by the Company as recorded in the Company's Weather Normalization Reserve and Contributions in Aid of Construction calculated in accordance with Board orders;

c) average deferred charges calculated in accordance with GAAP and Board orders; and,

d) allowances for inventory and working capital, calculated in accordance with Board orders.

Average deferred charges, which are costs that have already been incurred and which are expected to be recovered through future revenue, were added to rate base commencing in 2003 in accordance with Board Order No. P.U.19 (2003). Inclusion of average deferred charges in rate base eliminated a major difference between the Company's rate base and invested capital, and represented a significant step towards Newfoundland Power's adoption of the asset rate base method.

Transitional Adjustment
The Transitional Amount referred to in section C.3.1 of this report will be shown as a regulatory liability on Newfoundland Power's balance sheet at December 31, 2005. If the Transitional Amount is recognized as revenue over a transition period, the remaining balance will be shown as a regulatory liability on the Company's balance sheet during the transition period (the "Unrecognized Transitional Amount"). This will continue until such time as the Transitional

[22] For example, in Order No. P.U. 3 (1995-96), the Board ordered that the change in accounting policy for general expenses capitalized be phased in prospectively over the period from January 1, 1995 to December 31, 1999. In Order No. P.U. 19 (2003), the Board also approved adoption of the market-related method of valuing Newfoundland Power's pension assets on a prospective basis beginning in 2003, and true-up adjustments to depreciation expense on a prospective basis over three years also commencing in 2003. Other examples of prospective changes in accounting policy include Order Nos. P.U. 17 (1987), P.U. 20 (1978) and P.U. 21 (1980), wherein the Board approved adoption of the CICA recommendations on pension accounting and the recording of certain deferred taxes on a prospective basis.

Amount has been fully recognized as revenue and the Unrecognized Transitional Amount is reduced to zero.

The Unrecognized Transitional Amount reflects revenue for which recognition has been deferred until future accounting periods, i.e., it is a deferred liability. For reasons similar to those which support the inclusion of Newfoundland Power's Weather Normalization Reserve and the deduction of deferred income taxes in the calculation of rate base, the average Unrecognized Transitional Amount should also be deducted in the calculation of Newfoundland Power's rate base commencing in 2006.

D. CONCLUSION

Adoption of the Accrual Method of revenue recognition will bring Newfoundland Power's revenue recognition policy into the mainstream of Canadian public utility practice. It will also result in a better matching of the Company's revenues and expenses.

Prospective recognition of the Transitional Amount over a transition period commencing in 2006 will enable customers to receive full benefit from the resultant revenue without impairing Newfoundland Power's financial integrity. This approach is also consistent with past Board practice in similar matters and with the Tax Settlement.

The subtraction of the average Transitional Amount from rate base is consistent with the existing treatment of deferred liabilities and with the asset rate base method.

Appendix A

Survey Results
Method of Revenue Recognition for Regulatory Purposes
Canadian Utilities

Utility	Accrual Method	Unknown[1]
Altalink L.P.	√	
Atco Ltd.	√	
B.C. Hydro	√	
Emera Inc.	√	
Enbridge Inc.	√	
Enersource Corporation	√	
Enmax Corporation	√	
Epcor Utilities Inc.		√
FortisAlberta	√	
FortisBC	√	
FortisOntario	√	
Gaz Metro Limited Partnership	√	
Hydro One Inc.	√	
Hydro Ottawa Holding Inc.		√
Hydro Quebec	√	
Manitoba Hydro-Electric Board	√	
Maritime Electric	√	
New Brunswick Power Corporation	√	
Newfoundland & Labrador Hydro	√	
Northwest Territories Power Corp.	√	
Ontario Power Generation Inc.	√	
Saskatchewan Power Corporation		√
Terasen Inc.		√
Toronto Hydro Corporation	√	
Union Gas Limited	√	
Yukon Electrical Company Ltd.	√	
Yukon Energy Corporation	√	
Totals	23	4

[1] These utilities did not respond to the survey.

Appendix B

Survey Results
Transitional Methodologies
Accrual Method of Revenue Recognition
Canadian Utilities

Utility	Revenue Always Recognized using Accrual Method	Transitional Methodology: Unknown [1]	Prospective	Retroactive
Altalink L.P.		√		
Atco Ltd.			√ [2]	
B.C. Hydro		√		
Emera Inc.	√			
Enbridge Inc.		√		
Enersource Corporation	√			
Enmax Corporation	√			
Epcor Utilities Inc.		√		
FortisAlberta	√			
FortisBC			√ [3]	
FortisOntario	√			
Gaz Metro Limited Partnership	√			
Hydro One Inc.	√			
Hydro Ottawa Holding Inc.		√		
Hydro Quebec	√			
Manitoba Hydro-Electric Board	√			
Maritime Electric				√ [4]
New Brunswick Power Corporation				√ [5]
Newfoundland & Labrador Hydro			√ [6]	
Northwest Territories Power Corp.	√			
Ontario Power Generation Inc.	√			
Saskatchewan Power Corporation		√		
Terasen Inc.		√		
Toronto Hydro Corporation		√		
Union Gas Limited	√			
Yukon Electrical Company Ltd.		√		
Yukon Energy Corporation	√			
Totals	13	9	3	2

1 Of these 9 utilities, six did not respond, two were unable to determine if they had always used the Accrual Method of revenue recognition, and one indicated that it had transitioned from the Billed Method to the Accrual Method but was unable to determine the transitional methodology used.

2 Atco Ltd.'s subsidiary, Atco Electric Ltd., switched from the Billed Method to the Accrual Method of revenue recognition in 1989. The accumulated Unbilled Revenue at the date of transition, which was described by Atco as being "insignificant", was fully recognized in its 1989 reported revenue.

3 FortisBC's predecessor, West Kootney Power and Light Company Ltd., switched from the Billed Method to the Accrual Method in 1979. The accumulated Unbilled Revenue at the date of transition, which is estimated to be in the vicinity of $4 million, was fully recognized in its 1979 reported revenue.

4 Maritime Electric switched from the Billed Method to the Accrual Method in 1994. The accumulated Unbilled Revenue at the date of transition was $3.7 million and this was recorded as a direct adjustment to the retained earnings balance on the company's balance sheet.

5 New Brunswick Power Corporation switched from the Billed Method to the Accrual Method in 1986. The accumulated Unbilled Revenue at the date of transition was $19.5 million and this was recorded as a direct adjustment to the retained earnings balance on the company's balance sheet.

6 Newfoundland & Labrador Hydro switched from the Billed Method to the Accrual Method in 2000. The accumulated Unbilled Revenue at the date of transition, which was approximately $3 million, was fully recognized in its 2000 reported revenue. The adoption of the Accrual Method affected only "rural" customers because Newfoundland & Labrador Hydro bills Newfoundland Power and major industrial customers on energy delivered to December 31 each year. That is why, compared to Newfoundland Power, Newfoundland & Labrador Hydro's accumulated Unbilled Revenue at the date of transition was relatively small.

Newfoundland Power Inc.

Forecast 2005 Unbilled Revenue

Billing Cycle	Forecast Billings Jan 2006[1]	% of Total	Meter Reading Dates Dec 2005	Meter Reading Dates Jan 2006	Days in Cycle	Days Before Jan. 1	Days After Jan. 1	% of Revenue[2] Before Jan. 1	% of Revenue[2] After Jan. 1
1	$ 3,450,197	7.78	Dec. 1	Jan. 3	33	30	3	7.07	0.71
2	2,857,290	6.44	Dec. 2	Jan. 4	33	29	4	5.66	0.78
3	2,538,483	5.72	Dec. 6	Jan. 5	30	25	5	4.77	0.95
4	2,117,760	4.77	Dec. 7	Jan. 6	30	24	6	3.82	0.95
5	2,099,014	4.73	Dec. 8	Jan. 7	30	23	7	3.63	1.10
6	2,098,864	4.73	Dec. 9	Jan. 9	31	22	9	3.36	1.37
7	2,348,873	5.29	Dec. 10	Jan. 10	31	21	10	3.59	1.70
8	1,696,744	3.82	Dec. 12	Jan. 11	30	19	11	2.42	1.40
9	2,548,789	5.74	Dec. 13	Jan. 12	30	18	12	3.45	2.29
10	2,376,796	5.36	Dec. 14	Jan. 13	30	17	13	3.04	2.32
11	2,696,661	6.08	Dec. 15	Jan. 16	32	16	16	3.04	3.04
12	2,396,654	5.40	Dec. 16	Jan. 17	32	15	17	2.53	2.87
13	2,180,242	4.91	Dec. 19	Jan. 18	30	12	18	1.97	2.94
14	2,194,647	4.95	Dec. 20	Jan. 19	30	11	19	1.82	3.13
15	2,466,501	5.56	Dec. 21	Jan. 20	30	10	20	1.85	3.71
16	2,056,583	4.63	Dec. 22	Jan. 23	32	9	23	1.31	3.32
17	1,926,165	4.34	Dec. 28	Jan. 24	27	3	24	0.48	3.86
18	2,701,883	6.09	Dec. 29	Jan. 25	27	2	25	0.45	5.64
19	1,622,854	3.66	Dec. 30	Jan. 26	27	1	26	0.14	3.52
	$ 44,375,000	100.00						54.40	45.60

Forecast of 2005 Unbilled Revenue

January 2006 Forecast Billings[3]	$44,375,000
January 2006 Forecast Forfeited Discounts	225,000
	44,600,000
Portion Allocated to 2005[3]	54.40%
2005 Unbilled Revenue	**$24,262,400**

Notes:

[1] Based on the Company's customer and energy sales forecast dated March 31, 2005, excluding energy sales to Memorial University and forfeited discounts; and, calculated using rates approved by the Board effective January 1, 2005 as per Order No. P.U. 50 (2004).

[2] Based on the assumption of equal revenue per day per billing cycle.

[3] As per line 24.

Newfoundland Power Inc.

Forecast Depreciation Expense
2005 - 2006
(000s)

		2005	2006
1	Generation	$ 3,064	$ 3,108
2	Substations	3,033	3,106
3	Transmission	2,823	2,910
4	Distribution	20,066	20,858
5	General Property	1,429	1,441
6	Transportation	2,057	2,186
7	Communications	872	866
8	Information Systems	4,504	4,530
9	Load Research Equipment	74	74
10			
11	Gross Depreciation Expense[1]	37,922	39,079
12			
13	Adjustment for True-up[2]	(5,793)	-
14			
15	Net Depreciation Expense[3]	$ 32,129	$ 39,079

Notes:
[1] Gross depreciation expense does not include the amortization of customer contributions.
[2] As approved in Order No. P.U. 19 (2003).
[3] As shown in Exhibit NP-14, Page 1 of 5, line 12.

Newfoundland Power Inc.

Pro Forma Comparison of Recovery Alternatives (000s)

	Unbilled Revenue	Cash Revenue
Depreciation Expense		
Forecast increase in depreciation expense[1]	$ 6,950	$ 6,950
Tax Effects	-	3,930 [4]
Revenue Requirement	6,950	10,880
Tax Settlement		
Forecast tax on 2005 Unbilled Revenue[2]	3,086	3,086
Tax Effects	-	1,745 [4]
Revenue Requirement	3,086	4,831
Total[3]	$ 10,036	$ 15,711

Notes:

[1] As shown in Section 3.2.2, Table 3.

[2] As shown in Exhibit NP-2.

[3] As shown in Section 3.2.2, page 22, line 6.

Forecast increase in unbilled revenue in 2006	$ 457
Proposed recognition of 2005 Unbilled Revenue in 2006	9,579
	$ 10,036

[4] Based on Newfoundland Power's marginal tax rate of 36.12%.

Newfoundland Power Inc.

Unbilled Revenue Increase Reserve[1]
(000s)

	1999	2000	2001[4]	2002	2003[6]	2004[7]	2005
Opening Balance	$ -	$ 361	$ 430	$ 430	$ 371	$ 371	$ 371
Adjustment to Gross Revenue	623 [2]	119 [3]	-	(96) [5]	-	-	(120) [8]
Income Tax Effects	(262)	(50)	-	37	-	-	44
Net Adjustment	361	69	-	(59)	-	-	(76)
Closing Balance	$ 361	$ 430	$ 430	$ 371	$ 371	$ 371	$ 295

Notes:

[1] Established in accordance with Order No. P.U. 36 (1998-1999).
[2] Resulted from the increase in rates effective February 1, 1999 as approved in Order No. P.U 36 (1998-99).
[3] Resulted from the increase in rates effective January 1, 2000 as approved in Order No. P.U. 20 (1999-2000).
[4] There was no rate adjustment in 2001.
[5] Resulted from the decrease in rates effective January 1, 2002 as approved in Order No. P.U. 29 (2001-2002).
[6] No adjustment was required in 2003 as the increase in rates in that year was calculated retroactively to January 1st in accordance with Order No. P.U. 23 (2003).
[7] There was no rate adjustment in 2004.
[8] Resulted from the decrease in rates effective January 1, 2005 as approved in Order No. P.U. 50 (2004).

Newfoundland Power Inc.

***Pro Forma* Rate Base[1]**
2006 - 2009
(000s)

		2006	2007	2008	2009
1	Rate Base : Existing Methodology[2]	$ 763,651	$ 781,325	$ 800,390	$ 813,989
2					
3	Transitional Adjustment[3]	(19,325)	(10,791)	(3,597)	-
4					
5	Rate Base : Proposed Methodology	$ 744,326	$ 770,534	$ 796,793	$ 813,989

Notes:

[1] For purposes of illustrating the rate base effects a transition period of three years (2006 - 2008) was assumed. The actual transition period is subject to determination by the Board.

[2] Based on Newfoundland Power's 5-year capital plan filed in conjunction with the Company's 2006 Capital Budget Application.

[3] Assumes recognition of the 2005 Unbilled Revenue over the period from 2006 through 2008 as follows:

	Opening Balance	Unbilled Revenue Increase Reserve Adjustment [A]	Amount Recognized	Closing Balance	Average [B] Balance
2006	$ 24,262	$ 295	$ 9,579	$ 14,388	$ 19,325
2007	14,388	-	7,194	7,194	10,791
2008	7,194	-	7,194	-	3,597
		$ 295	$ 23,967		

Notes:

[A] Disposition of the Unbilled Revenue Increase Reserve as per section 3.2.3 of the Evidence.

[B] The average balance is calculated as (opening balance + closing balance)/2.

Asset Rate Base Method Review
(filed in compliance with Order No. P.U. 19 (2003))

September 2005

Table of Contents

1.0 BACKGROUND

1.1 The 2003 General Rate Order

In Order No. P.U. 19 (2003) (the "2003 GRO"), the Board found that the Asset Rate Base Method ("ARBM") should replace the Invested Capital Method used to calculate the return on rate base for Newfoundland Power ("the Company"). Both methods are valid accounting methodologies applied to convert cost of capital to return on rate base. However, the ARBM is more widely recognized, less complicated and has fewer variables. ARBM is calculated simply by multiplying the weighted average cost of capital by the average rate base. Both the average rate base and weighted average cost of capital are regulated by the Board.

As approved in the 2003 GRO, the transition to the ARBM began with the Company including average deferred charges in the computation of average rate base.[1] Including average deferred charges in the computation of average rate base brought the Company closer to the full implementation of ARBM. As a further step toward full implementation of ARBM, the Board ordered Newfoundland Power to review the remaining reconciling items between average rate base and average invested capital as identified by Grant Thornton.

1.2 Adopting ARBM

In compliance with the 2003 GRO, the Company filed *A Report on the Asset Rate Base Methodology* ("the Report") with its 2006 Capital Budget Application. The Report provided a review of each of the remaining reconciling items, assessed the appropriateness of their inclusion in Newfoundland Power's rate base, and provided an illustration of the impact on revenue requirement of moving to the ARBM based on 2004 test year costs.

The Report concluded that no change to the rate base will be required to address the reconciling items under the ARBM. However, the method used to calculate each item may need review from time-to-time.

This *Asset Rate Base Method Review* (the "Review") provides an update on the transition to ARBM based on the recommendations of the Report, taking into account the impact of Newfoundland Power's proposals with respect to recognizing revenue on an accrual basis beginning in 2006.

2.0 RECONCILING ITEMS

2.1 The Reconciling Items

In Newfoundland Power's 2003 general rate application (the "2003 GRA"), Grant Thornton provided a reconciliation of average invested capital and average rate base (the "Grant Thornton Reconciliation"). The Grant Thornton Reconciliation is provided in Table 1.

[1] The calculation of average rate base is provided in Return 3 of the Company's Annual Report to the Board.

Table 1
Reconciliation of Average Invested Capital and Average Rate Base [2]
2004 Test Year
(000s)

Average Invested Capital	$700,244
Average Rate Base	703,102
Difference	$(2,858)
Reconciliation:	
Plant (primarily construction in progress)	$1,674
Corporate income tax deposit	6,949
Materials and supplies (actual vs. allowance)	773
Working capital (actual vs. allowance)	(20,957)
Common equity (book vs. regulated)	8,703
	$(2,858)

A brief discussion of each of the reconciling items follows.

2.2 Plant (primarily construction in progress)

Plant refers to Newfoundland Power's investment in those physical assets necessary to deliver service to its customers. Plant is the principal component and the starting point for the calculation of average rate base.[3]

The difference in plant as reflected in the Company's average invested capital and its average rate base relates primarily to construction work in progress ("CWIP").

Newfoundland Power's invested capital reflects the cash investment in CWIP at December 31st, as reflected in the Company's financial statements. The inclusion of CWIP in the financial statements is in accordance with accepted financial accounting practice.

The calculation of Newfoundland Power's average rate base specifically excludes CWIP on the conceptual basis that CWIP is not yet "used and useful" in the provision of service to customers.

Since the average invested capital calculation includes the average CWIP in that year and the average rate base calculation excludes CWIP, there will continue to be ongoing differences

[2] Newfoundland Power 2003 General Rate Application, Grant Thornton, Supplementary Evidence April 4, 2003, Exhibit II.
[3] See Returns 3 and 4 of the Company's Annual Report to the Board.

between plant amounts for average rate base and average invested capital even after the ARBM has been fully adopted.

2.3 Corporate Income Tax Deposit

The corporate income tax deposit was included in the calculation of regulated average invested capital for the 2004 test year. However, it was not included in the calculation of average rate base for the 2004 test year.

In June 2005, Newfoundland Power settled the outstanding tax reassessments related to the income tax deposit. The income tax deposit was refunded to Newfoundland Power in August 2005, thus eliminating it as a reconciling item between average invested capital and average rate base as of 2006.

2.4 Materials and Supplies (actual vs. allowance)

Newfoundland Power's average invested capital recognizes its actual investment in materials and supplies inventory in that year, as reflected in its financial statements. The amount included in the financial statements is calculated in accordance with accepted financial accounting practice.

Current regulatory practice in the utility industry provides for a materials and supplies allowance to be included in rate base. The materials and supplies allowance recognizes, and permits recovery of, the cost of inventory for day-to-day operations. Newfoundland Power calculates a materials and supplies allowance in accordance with Board Orders by averaging the monthly balance of materials and supplies less an expansion factor.[4]

Use of an expansion factor in calculating the materials and supplies allowance for inclusion in Newfoundland Power's average rate base is the primary reason for the difference between average rate base and average invested capital related to materials and supplies.

2.5 Working Capital

Working capital from an accounting perspective (i.e., balance sheet working capital) is the difference between current assets and current liabilities at the balance sheet date. It is only a snapshot of working capital at a specific point in time (e.g. year-end) and is not indicative of (nor intended to be indicative of) a company's ongoing working capital requirement which varies from day-to-day.

Current regulatory practice in the utility industry provides for a cash working capital allowance ("CWC Allowance") to be included in rate base. A CWC Allowance is typically calculated using a lead/lag study that examines the timing differences between when revenue is collected and when particular expenses are paid. The Company's method for calculating the CWC Allowance to be included in average rate base was approved by the Board in Order No. P.U. 37 (1984).

[4] This method of calculating the materials and supplies allowance was approved by the Board in Order No. 1 (1974).

The historically large negative working capital calculated from Newfoundland Power's year-end balance sheet primarily reflects the Company's current accounting practices for revenue recognition. At the end of each financial year, the Company's balance sheet historically included amounts payable to Hydro for purchased power to December 31st.[5] However, the Company's balance sheet has not reflected unbilled amounts due from customers in respect of electricity deliveries for December that are billed in January of the following year.

2.6 Common Equity (book vs. regulated)

Book common equity is the common shareholders' equity as reflected in the Company's financial statements.

Newfoundland Power's regulated common equity is higher than book common equity. This is because regulated common equity has been increased by the cumulative amount of non-regulated expenses net of income taxes.[6]

The inclusion of cumulative non-regulated expenses in calculating regulated common equity is essentially a legacy issue for Newfoundland Power. As there appears to be no regulatory policy justification for continuing this practice, it would be practical and in the interests of regulatory transparency to discontinue its use.

3.0 IMPACTS OF ACCOUNTING POLICY CHANGES

The Company is proposing a change from recognizing revenue on a billed basis to an accrual basis as of January 1, 2006. The Company also proposes to discontinue the use of regulated common equity in favour of book equity in determining average invested capital beginning in 2006. (This combination of proposals is referred to as the "Proposed Method").

In addition, the recent CICA accounting guideline, AcG-19,[7] requires rate-regulated entities like Newfoundland Power to record regulatory assets and liabilities[8] on their balance sheet. To comply with AcG-19, Newfoundland Power will be required to report Unbilled Revenue on its December 31, 2005 balance sheet separately as (i) accounts receivable and (ii) a corresponding regulatory liability.[9]

---

5 Purchased power from Hydro is Newfoundland Power's largest expense. It represents over 60% of revenue on an annual basis.

6 See Return 19 of the Company's Annual Report to the Board.

7 CICA accounting guidelines are a component of the CICA Handbook and are therefore a source of GAAP. Accounting guideline ACG-19 titled *disclosures by entities subject to rate regulation* was issued in May 2005.

8 Regulatory assets and liabilities are created when regulators require revenues and/or expenses to be recognized in a manner other than that normally required by GAAP. Regulatory assets are amounts expected to be recovered from customers in future periods through the ratemaking process. Regulatory liabilities are amounts expected to be refunded or applied for the benefit of customers in future periods through the ratemaking process.

9 This differs from previous disclosure of the assets and regulatory liability associated with unbilled revenue when the two were netted for balance sheet reporting purposes.

This section of the Review highlights the impacts of the Proposed Method and AcG-19 on the reconciliation between average invested capital and average rate base. Specific *pro forma* impacts on working capital, average rate base, and average invested capital for the period 2006 to 2009 are identified, together with a summary of the overall impacts associated with the Proposed Method.

3.1 Working Capital

The new balance sheet reporting requirements introduced in AcG-19 will change Newfoundland Power's balance sheet working capital from a large negative balance to a positive balance. This occurs because the Company's balance sheet at December 31, 2005 will fully reflect all current receivables and payables to December 31st, including all unbilled amounts due from customers in respect of electricity deliveries. This also assumes that disposition of the corresponding regulatory liability is subject to Board determination and is therefore not recorded as a current liability.

As a result of the new balance sheet reporting requirements, the difference between Newfoundland Power's CWC Allowance and balance sheet working capital will be substantially eliminated.

Table 2 provides a comparison of the *pro forma* differences between the CWC Allowance and balance sheet working capital for 2006 to 2009 before and after implementation of the new balance sheet reporting requirements introduced in AcG-19.

Table 2
***Pro Forma* Working Capital Differences**
2006 – 2009
(000s)

Reconciling Item	2006	2007	2008	2009
Before Implementation of AcG-19				
Balance Sheet Working Capital	($18,316)	($18,549)	($18,856)	($18,811)
CWC Allowance	5,709	5,824	5,897	5,989
Difference	($24,025)	($24,373)	($24,753)	($24,800)
After Implementation of AcG-19				
Balance Sheet Working Capital	$6,174	$6,277	$6,207	$6,546
CWC Allowance	5,709	5,824	5,897	5,989
Difference	$465	$453	$310	$557

There will likely always be small differences between balance sheet working capital and the CWC Allowance because of the different methodologies which underlie the calculations.

3.2 Average Rate Base

Newfoundland Power's proposal to change from recognizing revenue on a billed basis to an accrual basis as of January 1, 2006 creates a transitional amount equal to the unbilled revenue at December 31, 2005 (the "Transitional Amount"). The Transitional Amount will be shown as a regulatory liability on Newfoundland Power's balance sheet at December 31, 2005.

Prospective recognition of the Transitional Amount over a transition period will enable customers to receive full benefit from the Transitional Amount in a manner which does not jeopardize Newfoundland Power's financial integrity. This approach is also consistent with past practice of the Board with respect to changes in accounting policy.[10]

If the Transitional Amount is recognized as revenue over a transition period, the remaining balance (the "Unrecognized Transitional Amount") will be shown as a regulatory liability on the balance sheet in subsequent years. This will continue until such time as the Transitional Amount has been fully recognized as revenue and the Unrecognized Transitional Amount is reduced to zero.

The Unrecognized Transitional Amount reflects revenue for which recognition has been deferred until future accounting periods, i.e., it is a deferred liability. For reasons similar to those which support the inclusion of Newfoundland Power's Weather Normalization Reserve and the deduction of deferred income taxes in the calculation of rate base, the average Unrecognized Transitional Amount should also be deducted in the calculation of Newfoundland Power's rate base commencing in 2006 (the "Transitional Adjustment").

The Transitional Adjustment and resulting *pro forma* average rate base for the period 2006 to 2009 are provided in Table 3.

[10] For example, in Order No. P.U. 3 (1995-96), the Board ordered that the change in accounting policy for general expenses capitalized be phased in prospectively over the period from January 1, 1995 to December 31, 1999. In Order No. P.U. 19 (2003), the Board also approved adoption of the market-related method of valuing Newfoundland Power's pension assets on a prospective basis beginning in 2003, and true-up adjustments to depreciation expense on a prospective basis over three years also commencing in 2003. Other examples of prospective changes in accounting policy include Order Nos. P.U. 17 (1987), P.U. 20 (1978) and P.U. 21 (1980), wherein the Board approved adoption of the CICA recommendations on pension accounting and the recording of certain deferred taxes on a prospective basis.

Table 3
***Pro Forma* Average Rate Base**
Existing Method vs. Proposed Method
2006 – 2009
(000s)

Rate Base	2006	2007	2008	2009
Existing Method [11]	$763,651	$781,325	$800,390	$813,989
Transitional Adjustment [12]	(19,325)	(10,791)	(3,597)	-
Proposed Method	$744,326	$770,534	$796,793	$813,989

3.3 Average Invested Capital

The proposed use of book equity for regulatory reporting purposes will eliminate common equity (book vs. regulated) as a reconciling item between average invested capital and average rate base.

3.4 Summary of Overall Impacts

As a result of new CICA pronouncements, Newfoundland Power's December 31, 2005 balance sheet reporting requirements will effectively eliminate the largest reconciling item between Newfoundland Power's average invested capital and average rate base; i.e., the difference between Newfoundland Power's CWC Allowance and balance sheet working capital.

Refund of the corporate income tax deposit, and the proposed use of book common equity for regulatory reporting purposes, also eliminates these two amounts as reconciling items between average rate base and average invested capital.

Of the remaining reconciling items, only slight differences exist. These slight differences will continue to occur because of the different accounting and regulatory treatments for calculating CWIP, working capital, other assets and liabilities, and materials and supplies.

Table 4 shows the *pro forma* differences and the reconciliation between average invested capital and average rate base under the Proposed Method for 2006 – 2009.

---

[11] Based on Newfoundland Power's 5-year capital plan filed with Board in the Company's 2006 Capital Budget Application

[12] Assumes recognition of the liability in 2006, 2007 and 2008 of $9,579,000, $7,194,200 and $7,194,200 respectively. This results in the liability being fully recognized as of year-end 2008.

Table 4
Proposed Method
***Pro Forma* Reconciliation of Average Invested Capital and Average Rate Base**
2006-2009
(000s)

Reconciling Item	**2006**	**2007**	**2008**	**2009**
Average Invested Capital	$745,752	$771,858	$798,100	$815,419
Average Rate Base	744,326	770,534	796,793	813,989
Difference	$1,426	$1,324	$1,307	$1,430
Reconciliation:				
Plant (primarily construction in progress)	$2,045	$2,102	$2,228	$2,105
Corporate Income Tax Deposit [13]	-	-	-	-
Materials and supplies (actual vs. allowance)	1,006	1,006	1,006	1,006
Working capital (actual vs. allowance)	465	453	310	556
Common Equity (book vs. regulated) [14]	-	-	-	-
Other Assets net of Other Liabilities [15]	(2,090)	(2,237)	(2,237)	(2,237)
	$1,426	$1,324	$1,307	$1,430

4.0 CONCLUSION

The assets of a utility which are attributable to regulated activities should be included in its rate base. Conceptually, therefore, the average rate base and the average invested capital of a utility should be essentially equal. If they are, then providing a rate of return on rate base equal to the weighted average cost of capital (i.e., the ARBM) should result in recovery of the full required return on invested capital.

With the implementation of Newfoundland Power's proposed accounting policy changes, average rate base and average invested capital will no longer be materially different. This will mark significant progress towards adoption of ARBM for calculating Newfoundland Power's return on rate base.

---

13 The corporate income tax deposit was refunded to the Company in August 2005 as a result of the tax case settlement and is no longer a reconciling item.

14 With the proposed use of book common equity for regulatory purposes, this will no longer be a reconciling item.

15 This includes other assets and other liabilities which are not currently included in average rate base but which are included in average invested capital, as shown in Appendix A. Other assets net of other liabilities were shown in previous reconciliations as part of working capital differences.

Newfoundland Power will address the small differences that will continue to exist as a result of the different accounting and regulatory treatments for calculating CWIP, working capital, other assets and liabilities, and materials and supplies, at its next general rate application.

Appendix A

Newfoundland Power Inc.

Other Assets and Liabilities
Pro Forma
2006 - 2009
(000s)

		2005	2006	2007	2008	2009
1	**Other Assets**					
2	Unbilled Revenue Increase Reserve[1]	$ 295	$ -	$ -	$ -	$ -
3	Finance Programs[2]	866	866	866	866	866
4		$ 1,161	$ 866	$ 866	$ 866	$ 866
5						
6	**Other Liabilities**					
7	Security Deposits[3]	$ 879	$ 879	$ 879	$ 879	$ 879
8	Long-term Pension Liability[4]	2,224	2,224	2,224	2,224	2,224
9		$ 3,103	$ 3,103	$ 3,103	$ 3,103	$ 3,103
10						
11	**Other Assets net of Other Liabilities[5]**	$ (1,942)	$ (2,237)	$ (2,237)	$ (2,237)	$ (2,237)
12						
13	**Average of Other Assets net of Other Liabilities**		$ (2,090)	$ (2,237)	$ (2,237)	$ (2,237)

Notes:
[1] The balance in the Unbilled Revenue Increase Reserve as shown in Exhibit NP-7. Newfoundland Power is proposing in this application to apply the remaining balance in the reserve against the 2005 Unbilled Revenue in 2006.
[2] Long-term customer receivables related to energy management programs such as *Wrap Up for Savings* .
[3] Amounts received from customers in accordance with the Company's *Schedule of Rates Rules & Regulations* as reasonable security for the payment of charges as may be required by the Company pursuant to its Board approved Customer Deposit Policy. Recognition of the liability indicates the Company's obligation to repay these amounts once all of the conditions for security have been satisfied.
[4] Long-term pension liability.
[5] Line 4 minus line 9.

Newfoundland Power Inc.

Forecast Working Capital Difference
2006
(000s)

		2005	2006
1	**Balance Sheet Working Capital (Invested Capital)**		
2			
3	Year End Accounts Receivable[1&4]	$ 75,515	$ 76,379
4	Year End Accounts Payable[2&4]	69,242	70,304
5	Working Capital - Balance Sheet	6,273	6,075
6			
7	Average Working Capital - Balance Sheet		6,174
8			
9			
10	**Cash Working Capital Allowance (Rate Base)**		
11			
12	Purchased Power Expense		$ 265,498
13	Operating Expenses		54,153
14	Non-regulated Expenses Net of Income Tax		(725)
15	Current Income Tax Expense		16,877
16	Base For Working Capital Allowance		$ 335,803
17			
18	Cash Working Capital Allowance Factor (1.7%)		1.7%
19			
20	Cash Working Capital Allowance		$ 5,709
21			
22			
23	**Working Capital Difference[3]**		$ 465

Notes:
[1] Exhibit NP-14, page 3 of 5, line 6 plus line 8.
[2] Exhibit NP-14, page 3 of 5, line 28.
[3] Line 7 minus line 20.
[4] For financial reporting purposes as of December 31, 2003 Newfoundland Power changed the balance sheet presentation of its long-term receivables and long-term payables to report them separately as other assets and liabilities. Prior to December 31, 2003, and in evidence filed in support of its 2003 General Rate Application, Newfoundland Power reported its long-term receivables and long-term payables as part of current assets and liabilities.

Newfoundland Power Inc.

Forecast Average Rate Base
2005 - 2006
(000s)

	2005	2006
Plant Investment	$ 1,148,875	$ 1,185,963
Deduct:		
Accumulated Depreciation	480,634	507,215
Contributions in Aid of Construction	20,822	21,033
Future Income Taxes	1,543	-
Weather Normalization Reserve	(10,162)	(9,036)
	492,837	519,212
	656,038	666,751
Add - Contributions Country Homes	575	575
Balance - Current Year	656,613	667,326
Balance - Previous Year	639,297	656,613
Average	647,955	661,970
Cash Working Capital Allowance (@1.7%)	5,556	5,709
Materials and Supplies	4,494	4,494
Forecast Average Deferred Charges	86,054	91,478
Average Unrecognized 2005 Unbilled Revenue[1]	-	(19,325)
Average Rate Base	$ 744,059	$ 744,326

Notes:
[1] Proposed adjustment to average rate base to reflect the average deferred liability in 2006, as referred to in section 3.2.4 of the evidence. See also Exhibit NP-8, note 3.

Newfoundland Power Inc.

Forecast Average Invested Capital
2005 - 2006
(000s)

		2005	2006
1	Debt	$ 393,291	$ 406,233
2	Preferred Equity	9,414	9,411
3	Book Common Equity[1]	320,293	330,108
4			
5	Average Invested Capital	$ 722,998	$ 745,752

Notes:
[1] As per the forecast balance sheet in Exhibit NP-14, Page 3 of 5. As proposed in the Application, common equity is not adjusted for cummulative non-regulated expenses.

Newfoundland Power Inc.

Pro Forma 2006 Formula Operation

Return on Rate Base Formula Approved by Order No. P.U. 36 (1998-99):

$$\textbf{Rate of Return on Rate Base} = \left[\frac{\text{Invested Capital}}{\text{Rate Base}} \times \text{Weighted Average Cost of Capital} \right] + \frac{Z}{\text{Rate Base}}$$

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 (Recognized in the rate of return on rate base calculation but not the weighted average cost of capital calculation.);

(b) Interest on Customer Deposits (Recognized in the weighted average cost of capital calculation but not the rate of return on rate base calculation.); and,

(c) Interest Charged to Construction (Recognized in the rate of return on rate base calculation but not the weighted average cost of capital calculation.).

Pro forma 2006 Rate of Return on Rate Base

$$\mathbf{8.75\%} = \left[\frac{\$\ 745{,}752^{1}}{\$\ 744{,}326^{2}} \times 8.75\%^{3} \right] + \frac{\$\ 66 + \$\ 30 - \$\ 246^{4}}{\$744{,}326^{2}}$$

Notes:

[1] 2006 forecast average invested capital as per Exhibit NP-12.

[2] 2006 forecast average rate base as per Exhibit NP-11.

[3] Weighted average cost of capital resulting from operation of the Automatic Adjustment Formula for 2005 as approved in Order No. P.U. 50 (2004). This reflects an allowed return on equity of 9.24% and is subject to change based on operation of Automatic Adjustment Formula for 2006.

[4] The component values for Z, as referred to above, approved for use in the Automatic Adjustment Formula in Order No. P.U. 19 (2003).

Newfoundland Power Inc.

Forecast Financial Statements
Statement of Earnings
(000s)

		2005	2006
1	Billed Revenue	$ 410,669	$ 417,069
2	2006 Unbilled Revenue Accrual[1]	-	457
3	2005 Unbilled Revenue[2]	-	9,579
4		410,669	427,105
5	Purchased Power Expense	258,144	265,498
6	Contribution	152,525	161,607
7			
8	Other Revenue	12,048	9,950
9			
10	Other Expenses:		
11	Operating Expenses	54,062	54,153
12	Depreciation Expense	32,129	39,079
13	Finance Charges	31,453	32,637
14		117,644	125,869
15			
16	Income Before Income Taxes	46,929	45,688
17	Income Taxes	15,356	15,335
18			
19	Net Income	31,573	30,353
20	Preferred Dividends	587	591
21			
22	Earnings Applicable		
23	to Common Shares	$ 30,986	$ 29,762
24			
25			
26	**Rate of Return Metrics**		
27			
28	Regulated Return on Book Equity	N/A[3]	9.24%
29	Return on Book Equity	9.67%	9.02%
30	Rate of Return on Rate Base	8.57%	8.56%

Notes:

1 The change in unbilled revenue for 2006 as referred to in section 3.1.3 of the evidence and shown in Exhibit NP-2, line 5.

2 The amount of the 2005 Unbilled Revenue proposed to be recognized in 2006, as referred to in section 3.2.2 of the evidence and shown in Exhibit NP-8, note 3.

3 In 2005, the return on equity for regulatory purposes is based on regulated common equity and not book equity as shown for 2006.

Newfoundland Power Inc.

Forecast Financial Statements
Statement of Retained Earnings
(000s)

		2005	2006
1	Balance at Beginning of the Year	$ 246,039	$ 253,904
2	Net Income for the Year	31,573	30,353
3		277,612	284,257
4	Dividends		
5	Preference Shares	587	591
6	Common Shares	23,121	17,999
7		23,708	18,590
8			
9	Balance at End of the Year	$ 253,904	$ 265,667

Newfoundland Power Inc.

Forecast Financial Statements
Balance Sheet
(000s)

ASSETS	2005	2006
Fixed Assets		
Property Plant and Equipment[1]	$ 1,086,880	$ 1,122,328
Less: Accumulated Amortization[2]	437,348	462,640
	649,532	659,688
Current Assets		
Accounts Receivable	68,157	69,021
Materials and Supplies, at average cost	5,500	5,500
Rate Stabilization Account	7,358	7,358
	81,015	81,879
Deferred Charges	89,256	93,701
Other Assets[3]	11,898	10,477
	$ 831,701	$ 845,745
SHAREHOLDERS' EQUITY AND LIABILITIES		
Shareholders' Equity		
Common Shares	$ 70,321	$ 70,321
Retained Earnings	253,904	265,667
Common Shareholder's Equity	324,225	335,988
Preference Shares	9,411	9,411
	333,636	345,399
Long-Term Debt	380,058	344,738
Current Liabilities		
Short-Term Borrowings	15,607	32,493
Accounts Payable and Accrued Charges	69,242	70,304
Current Installments of Long-Term Debt	4,250	35,320
	89,099	138,117
Future Income Taxes	1,543	-
Other Liabilities [4]	27,365	17,491
	$ 831,701	$ 845,745

Notes:
[1] Property Plant and Equipment is shown net of contributions.
[2] Accumulated Amortization is shown net of amortization of contributions.
[3] Other Assets include the Weather Normalization Reserve.
[4] Other Liabilities include the deferred liability associated with the transition to the Accrual Method of revenue recognition.

Newfoundland Power Inc.

Forecast Financial Statements
Statement of Cash Flows
(000s)

		2005	2006
1	Cash From (Used In) Operations		
2	Net Income	$ 31,573	$ 30,353
3	Reduction in Income Tax Deposit	6,949	-
4			
5	Items Not Affecting Cash:		
6	Amortization of Capital Assets	32,129	39,079
7	Future Income Taxes	42	(1,543)
8	Weather Normalization Reserve Transfers	315	1,126
9	Accrued Employee Future Benefits	(5,896)	(5,322)
10	Amortization of Deferred Charges	(177)	878
11	Changes in Non-Cash Working Capital[1]	(3,198)	(9,384)
12		61,737	55,187
13			
14	Cash From (Used In) External Financing		
15	Redemption of Preference Shares	(6)	-
16	Net Proceeds From Long Term Debt	59,755	-
17	Repayment of Long Term Debt	(4,250)	(4,250)
18	Short-Term Borrowings	(42,502)	16,886
19	Contributions and Security Deposits	1,449	1,500
20	Dividends		
21	Preference Shares	(587)	(591)
22	Common Shares	(23,121)	(17,999)
23		(9,262)	(4,454)
24			
25	Cash From (Used In) Investing		
26	Net Capital Expenditures	(53,081)	(50,733)
27	Long Term Receivables	139	-
28		(52,942)	(50,733)
29			
30	Increase (Decrease) In Cash	(467)	-
31	Cash, Beginning	467	-
32	Cash (Bank Indebtedness), Ending	$ -	$ -

Notes:

[1] Changes in non-cash working capital reflect the accounts receivable associated with unbilled revenue as at December 31, 2005 and December 31, 2006.

Newfoundland Power Inc.

Forecast Financial Statements
2005 - 2006
Major Inputs and Assumptions

Figures for 2005 and 2006 are based on the most recent Company forecasts, estimates and calculations. Specific assumptions include:

Energy Forecasts :	Energy forecasts are based on economic indicators taken from the Conference Board of Canada forecast dated January 31, 2005.
Revenue Forecast :	The revenue forecast is based on the Customer and Energy Sales Forecast dated March 31, 2005.
Purchased Power :	Rates charged by Newfoundland and Labrador Hydro, in effect at July 1 2004, that resulted from Order No. P.U. 20 (2004), are used to forecast purchased power expense for 2005 and 2006.
	Beginning January 1, 2003, $5.6 million of the 2001 balance in the Hydro Equalization Reserve is being amortized over a five year period. The amortization period ends December 31, 2007.
Operating Costs:	Retirement Allowances related to the 2005 Early Retirement Program are being amortized on an after-tax basis over a 24-month period from April 1, 2005 to March 31, 2007 as approved in Order No. P.U. 49 (2004).
Pensions :	Pension costs related to the 2005 Early Retirement Program are being amortized over a 10-year period from 2005 to 2015 as approved in Order No. P.U. 49 (2004).
	Pension funding is based on the Actuarial Valuation dated December 31, 2003 and a Board approved schedule of funding payments.
	Pension expense discount rate is assumed to be 5.50% in 2006.
Depreciation Rates :	Depreciation rates are based on the 2002 depreciation study dated September 5, 2002, as approved by the Board in Order No. P.U. 19 (2003).
Short-Term Interest Rates :	Average Short-term interest rates are assumed to be 3.25% in 2005 and 4.00% in 2006.
Long-Term Debt :	A $60.0 million long-term debt issue was completed on August 15, 2005. The debt was issued for 30 years at a coupon rate of 5.44%. Debt repayments will be in accordance with the normal sinking fund provisions for current outstanding debt.
Dividends :	Common share dividends are paid to maintain a book common equity ratio at or below 45%.
Income Tax :	Income tax expense reflects a statutory income tax rate of 36.12% and the effects of the Tax Settlement. A copy of the Tax Settlement is provided as Exhibit NP-1.

Newfoundland Power Inc.

Forecast 2006 Financial Results
(000s)

		2006 Exisiting[1]	2006 Proposed[2]
1			
2	Billed Revenue	$ 417,069	$ 417,069
3	2006 Unbilled Revenue Accrual	-	457
4	2005 Unbilled Revenue	-	9,579
5		417,069	427,105
6	Purchased Power Expense	265,498	265,498
7	Contribution	151,571	161,607
8			
9	Other Revenue	9,950	9,950
10			
11	Other Expenses:		
12	Operating Expenses	54,153	54,153
13	Depreciation	39,079	39,079
14	Finance Charges[3]	32,535	32,637
15		125,767	125,869
16			
17	Income Before Income Taxes	35,754	45,688
18	Income Taxes[3]	15,368	15,335
19			
20	Net Income	20,386	30,353
21	Preferred Dividends	591	591
22			
23	Earnings Applicable		
24	to Common Shares	$ 19,795	$ 29,762
25			
26			
27	**Rate of Return Metrics**		
28			
29	Regulated Return on Book Equity	6.25%	9.24%
30	Return on Book Equity	6.03%	9.02%
31	Rate of Return on Rate Base	7.02%	8.56%

Notes:

[1] Reflects the Billed Method of revenue recognition for financial reporting and regulatory purposes, and the income tax effects of the Tax Settlement.

[2] Based on the proposals contained in section 3.4 of the evidence.

[3] The change in finance charges and income taxes is due to the change in dividend payout required to maintain a consistent capital structure with common equity at or below 45%.

JTBrowne
Consulting

NEWFOUNDLAND POWER

Changes to Regulatory Accounting Policies

September 28, 2005

Costing &
Regulatory Consulting

TABLE OF CONTENTS

Phone: 416-251-3204
Email: john.browne@sympatico.ca

2045 Lakeshore Blvd. W. #809
Toronto, Ontario M8V 2Z6

1 - INTRODUCTION

Newfoundland Power ("NP") is requesting that the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") approve certain changes to its regulatory accounting policies. These changes would affect how NP calculates the revenue requirement it is allowed to recover through its regulated rates.

To support its request, NP has asked me as a Chartered Accountant and economist with experience in addressing regulatory issues to address the following[1]:

- relationship between regulatory accounting policies ("RAP") and generally accepted accounting principles ("GAAP");
- accrual vs. billed method for recognizing revenue;
- treatment of unrecognized unbilled revenue at the end of 2005; and
- accounting policies related to NP's transition to the asset rate base method.

Each of the above issues is addressed in the following sections.

In preparing this report, I have relied on financial data and other information about NP that was provided to me by NP. In carrying out my mandate, I was not asked and did not perform any audit or other verification procedures on this data and information.

1 A copy of my resume has been attached as Exhibit JTB-1.

2 - RAP VS GAAP

NP is proposing to change certain regulatory accounting policies. As background to assist the PUB in reviewing its proposals, NP has asked me to set out the relationship between regulatory accounting policies ("RAP") and generally accepted accounting principles ("GAAP"). In particular, NP has asked me to address how GAAP affects RAP and how RAP affects what should be reported in accordance with GAAP.

OBJECTIVES

Both regulators and financial accountants require accounting policies to establish a utility's costs. There is usually a great deal of consistency between the two sets of policies. However, for most utilities, there are at least some differences. The differences usually arise from differences in objectives.

Regulators normally set rates on a basis that reflects the costs of providing regulated service, where costs include a fair return. With return on rate base regulation, such as that used in regulating NP, there is a very tight relationship between costs and rates. With many of the incentive / performance based methodologies, the link may not be as direct, but is usually still there. This creates the need to establish regulatory accounting policies to determine the costs to be recovered through the rates in each period.

In preparing the financial statements for a utility, financial accountants must also establish the costs of each period (i.e., expenses). In doing so, they apply GAAP. In Canada, the primary source of GAAP is the CICA Handbook – Accounting ("CICA Handbook") which is maintained by the Accounting Standards Board ("AcSB") of the Canadian Institute of Chartered Accountants ("CICA").

Although regulators and financial accountants are both attempting to establish a utility's costs, they have different objectives:

- Regulators are attempting to set just and reasonable rates. They expect to have a direct impact on the economic results of a utility.

- Financial accountants are attempting to report on the economic position of the reporting entity and the change in its economic position.[2] They do not intend to have a direct impact on the economic results of a utility. They are attempting only to report those economic results.

The difference in objectives can result in differences between RAP and GAAP. Still, GAAP is usually a major influence on RAP, and although RAP does not determine GAAP, it can affect what should be reported in accordance with GAAP.

[2] See CICA Handbook; Section 1000 - Financial Statement Concepts; para. 1000.15.

IMPACT OF GAAP ON RAP

GAAP is a major influence on the RAP established by each regulator and is usually the starting point for RAP:

- GAAP is a widely accepted set of principles and rules for determining the costs of a period.

- GAAP normally recognizes costs as the amount originally paid to acquire goods or services. This is consistent with the objective of many regulators to allow a regulated entity to recover the actual costs it has incurred, but no more.

- GAAP normally results in costs being expensed in the period that they contribute to the provision of goods or services. Regulators normally seek such a matching since it is in accordance with the principle of intergenerational equity.

Although regulators generally refer to GAAP in setting their RAP, they are usually not required to do so and there are a number of examples where regulators have deviated from GAAP. For example:

- Regulators recognize the cost of equity as a cost to be recovered through rates even though it is not a cost recognized by GAAP.

- Regulators often require that restructuring costs, such as NP's recent early retirement program, be recovered over a period of years. However, GAAP normally requires that these costs be expensed in the period that the restructuring decision is made.

- Regulators may defer the recovery of certain costs so as to maintain rate stability and predictability, even though GAAP would normally require that the costs be expensed in the period they are incurred.

- Regulators often allow utilities to defer and recover in future periods large costs that were not considered in setting current rates, even though GAAP would normally require that they be expensed in the period the costs are incurred.

Presumably, regulators deviate from GAAP because they believe that it results in rates that are more just and reasonable. For example:

- Regulators allow a return on equity because it is generally considered just and reasonable for equity investors to receive a fair return on their investment. More importantly, if utilities were not able to recover the cost of equity, they would not be able to attract the capital necessary to provide regulated service.

- Regulators may allow the future recovery of costs not covered by existing rates so as to provide a utility with a reasonable opportunity to recover its costs in accordance with the cost of service standard.

- Regulators may use variance accounts to deal with the uncertainty of costs that are difficult to estimate. The variance accounts help prevent a utility from substantially under-recovering or over-recovering such costs.

IMPACT OF RAP ON GAAP

Regulators cannot set GAAP but can affect what should be reported in accordance with GAAP.

ABILITY TO SET GAAP

Regulators can set whatever accounting policies they want for regulatory purposes, so long as the policies are consistent with the legislation under which they operate. However, they cannot set GAAP – i.e., the accounting polices employed for financial reporting purposes. Section 1100 of the CICA Handbook "Generally Accepted Accounting Principles" makes this very clear:

> *An entity may be required to prepare financial statements in accordance with regulatory, legislative or contractual requirements. … if the basis of accounting used to prepare such financial statements conflicts with the requirements of this Section, that basis cannot be described as being in accordance with GAAP.*[3]

Section 1100 contains a temporary exemption for rate-regulated enterprises[4]. However, it applies to the recognition of assets and liabilities arising from rate regulation – i.e., reporting on the economic impacts of regulatory accounting policies rather than reporting on the basis of the regulatory accounting policies:

> *Pending completion of a separate project on rate-regulated operations, an entity is not required to apply this Section to the recognition and measurement of assets and liabilities arising from rate regulation. Entities are required to apply this Section to all other assets and liabilities for fiscal years beginning on or after October 1, 2003.* [5]

As described below, regulatory decisions can have an economic impact on a regulated utility. They can result in the creation of economic benefits and obligations. Where the appropriate conditions are met, these impacts should be reported as assets and liabilities in a utility's financial statements in accordance with GAAP.

---

[3] CICA Handbook; Section 1100 - Generally Accepted Accounting Principles; para. 1100.12.

[4] It is expected that this exemption will be removed when the CICA issues a recommendation of accounting for the effects for rate regulation.

[5] CICA Handbook; Section 1100 - Generally Accepted Accounting Principles; para. 1100.34.

At times, it may appear that utilities are following their RAP for financial reporting purposes. However, this reporting reflects the economic impact of the regulatory policies rather than the policies themselves.

For example, GAAP normally requires that companies recognize the revenue from services provided in the period rather than the revenue billed in the period. Still, NP recognizes an amount of revenue in its financial statements equal to its billed revenue – i.e., the amount recognized in accordance with its RAP.

With NP's current RAP, unbilled revenue is ignored in the current period and is used to reduce the revenue requirements recoverable from future rates. As a result, the unbilled revenue is not available for NP's shareholders – at least not in the current period. From a financial reporting perspective, it represents a regulatory liability. To recognize this economic impact of its RAP (i.e., a liability equal to unbilled revenue), NP's revenues reported in accordance with GAAP are reduced by the increase in unbilled revenue – i.e., reduced to the billed amount.

The current view on how regulators can affect financial reporting is reflected in the notes to Nova Scotia Power Inc.'s 2004 financial statements:

> *The Company's accounting policies are subject to regulation by the Nova Scotia Utility and Review Board. The UARB exercises statutory authority over matters such as construction, rates and underlying accounting practices. In order to recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under generally accepted accounting principles…*

Similar wording can be found in the notes to the financial statements of other Canadian utilities.

ECONOMIC IMPACT OF REGULATION

Through the rate setting process, regulators can create future economic benefits and obligations. For example, a regulator may decide that differences between the estimated and actual cost of oil used in generating electricity will be deferred and included in the determination of future rates.

- If actual oil costs exceed the estimated amounts, the difference will be included in the determination of future revenue requirements and the utility will be given the opportunity to recover the additional costs through future rates. The right to receive additional future revenues because actual oil costs exceeded the estimated costs represents an economic benefit.

- If actual oil costs are less than the estimated amounts, the difference will be deducted in the determination of future revenue requirements. The requirement to reduce future rates because actual oil costs were less than the estimated costs represents an economic obligation.

This is recognized in Accounting Guideline 19, "Disclosures By Entities Subject To Rate Regulation**"** ("AcG-19")[6]:

> *Rate regulation can affect both the revenue-generating ability of an entity and the period in which its revenues are earned, and may, in certain circumstances, result in the creation of material economic benefits and obligations. It is, therefore, an important consideration in evaluating the financial performance of entities with rate-regulated operations.*[7]

Under certain conditions, these benefits and obligations may meet the requirements for recognition as assets or liabilities in accordance with GAAP. Essentially, these requirements are met when, as a result of a past transaction or event, it is probable that there will be an increase or decrease in future revenues from what would otherwise exist. In particular, the key conditions include:

- Regulated rates are designed to recover the costs of providing service[8].
- There will be an increase (decrease) in allowed rates, from what would otherwise be allowed, sufficient to cover the regulatory asset (liability).
- Future rates sufficient to cover the utility's costs, including any regulatory assets, will be chargeable and collectible from customers.

DISCLOSURE

In May of this year, the CICA issued AcG-19. This guideline provides direction on how companies should report the impacts of rate regulation[9]. It deals only with disclosure issues. It provides no guidance on whether a utility should recognize a regulatory asset or liability[10].

The Guideline will require utilities such as NP to disclose the nature and extent of their regulated operations, the methodologies under which they are regulated and the entities that regulate them. To the extent that they recognize the effects of rate regulation, they

---

6 For the details of AcG-19, see Exhibit JTB-2.

7 CICA Accounting Handbook; Accounting Guideline AcG-19 - Disclosures By Entities Subject To Rate Regulation; para. 4.

8 This means allowed rates are established so that, based on expected volumes and costs as recognized in the regulatory process, revenues will equal costs, including a fair return on investment.

9 The Guideline is effective for fiscal years ending on or after December 31, 2005.

10 For example, both NP and Newfoundland and Labrador Hydro have rate stabilization accounts that they recognize as regulatory assets. AcG-19 provides no guidance on whether or not the utilities should recognize these assets, but given that the utilities have recognized them, it provides guidance on what the utilities should disclose.

will have to identify the impact on their financial statements and the justification for the accounting treatment employed.

One of the requirements in AcG-19 highlights the impact of rate regulation on a utility's balance sheet and reflects the view that regulators cannot set GAAP but can affect what should be reported in accordance with GAAP.

> *Assets and liabilities, including those recognized as a result of the effects of rate regulation, should be offset only when specifically permitted or required by another Section or Guideline.*[11]

For example, up until now, NP has not reflected its unbilled revenue on its balance sheet because it has used the billed method in setting rates. Under the currently accepted view of accounting for the effects of rate regulation, NP's unbilled revenue represents an addition to its accounts receivable[12]. However, the unbilled revenue will be used to reduce NP's revenue requirement in the following period. Therefore, NP has a regulatory liability equal to its unbilled revenue. NP's past practice effectively netted the regulatory liability against the accounts receivable related to the unbilled revenue[13].

Under AcG-19, utilities will not be allowed to continue with this netting. NP will have to include unbilled revenue in its accounts receivable on its balance sheet, the same as any other company. However, it will also be allowed to recognize a regulatory liability equal to the amount of its unbilled revenue. Net income and equity will not be affected since the unbilled revenue in accounts receivable will be offset by the regulatory liability[14].

CURRENT STATUS

The issue of accounting for the effects of rate regulation has been under review in Canada for a number of years.

At the current time, the CICA Handbook provides limited direction on how to recognize and measure the effects of rate regulation. The direction that exists deals with a limited number of specific issues, such as income taxes.

Despite the limited direction, practice goes far beyond what is specifically addressed in the CICA Handbook. This practice has been accepted as in accordance with GAAP by regulated entities and their auditors.

---

[11] CICA Handbook; Accounting Guideline AcG-19 - Disclosures By Entities Subject To Rate Regulation; para. 10.

[12] As noted in the above quote from Section 1000, utilities are permitted to recognize regulatory assets and liabilities in appropriate circumstances. However, they must apply GAAP to all other assets and liabilities. Therefore, NP must recognize the unbilled revenue as part of its accounts receivable.

[13] This was a common practice for Canadian regulated utilities.

[14] This assumes that NP continues to recognize its revenue on the billed basis for rate setting purposes.

As discussed above, the CICA has recently issued an accounting guideline that provides comprehensive direction for disclosing the effects of rate regulation. However, it deals only with disclosure and provides no direction on how to recognize and measure these effects.

Due to the limited direction in Canada, Canadian accountants have referred to US standards in determining how to account for the effects of rate regulation. The key US standard in this area is FAS 71 “Accounting for the Effects of Certain Types of Regulation”. It provides comprehensive direction for recognizing the effects of rate regulation and was published in 1982.

FAS 71 recognizes that regulators can create assets and liabilities under certain conditions[15]. FAS 71 is consistent with the view that regulators cannot set GAAP, but as a result of their regulatory decisions, can create economic benefits and obligations that should be reported as assets and liabilities in accordance with GAAP.

In 1999, the CICA created a Study Group to look into the issue of financial reporting by rate-regulated enterprises. The work of the Study Group was summarized in the research report “Financial Reporting by Rate-Regulated Enterprises” that was published in 2002.[16] As noted at the beginning of the Study Group’s report, the views expressed in that report are those of the Study Group and do not necessarily reflect the views of the CICA.

The Study Group’s conclusions and recommendations were broadly consistent with established practice and FAS 71. However, the AcSB was not convinced. The “Decision Summary” from the AcSB’s meetings for July 9-10, 2003, contained the following statement:

> *The AcSB discussed the arguments in favour of treating certain deferrals as assets or liabilities but expressed significant misgivings that such deferrals meet the asset or liability definitions in Handbook Section 1000, Financial Statement Concepts.*

Although there are questions as to whether utilities will continue to be allowed to recognize regulatory assets and liabilities, the issue is still being debated. It may be argued that if the AcSB had already decided against continued recognition, it would not have spent the time and effort on issuing AcG-19.

It appears that at least one of the AcSB’s concerns is that the benefits and obligations created by rate regulation may be conditional. For example, if a regulator decides to defer the recovery of a cost to a future period, is the decision final or is the future recovery of the cost conditional on a future decision of the regulator?

---

15 Financial Accounting Standards Board; FAS 71 - Accounting for the Effects of Certain Types of Regulation; para. 9–10.

16 The Study Group consisted of ten Chartered Accountants chosen by the CICA to represent a number of perspectives. I was chairman of the Study Group.

The "Decision Summary" from the AcSB's meetings for December 1-2, 2004, contained the following statement:

> *The AcSB reaffirmed its previous decision that the GAAP conceptual framework should apply equally to all entities, whether or not they are subject to rate regulation, and discussed the circumstances in which rate regulation could give rise to assets and liabilities as defined in Section 1000, Financial Statement Concepts. The AcSB:*
>
> - *agreed that in order for rate regulation to create an asset or liability, the regulator's actions must result in the entity having an unconditional right (or obligation) to charge higher (or lower) rates in the future;*
>
> ….
>
> - *directed staff to invite entities subject to rate regulation and other interested stakeholders to provide actual fact patterns demonstrating how a regulator's actions can create unconditional rights and obligations meeting the above-mentioned criteria.*

A draft standard (i.e., exposure draft) on accounting for the effects of rate regulation is expected in 2006[17].

Regardless of what the CICA decides, it will not prevent regulators from deviating from GAAP for regulatory purposes. Moreover, it is likely that regulators will continue to believe that just and reasonable rates may require such deviations in certain specific cases.

CONCLUSION

GAAP provides useful guidance for establishing the costs that should be recovered in a given period and is usually the starting point for establishing the RAP on which regulated rates will be based. However, regulatory objectives differ from those of financial accounting, and in certain cases, this may require deviations from GAAP so as to produce just and reasonable rates.

Regulators cannot set GAAP but through the rate setting process can affect what should be reported in accordance with GAAP. The regulatory process can create future economic benefits and obligations that, under certain conditions, should be reported as assets or liabilities in accordance with GAAP.

In Canada, accounting for the effects of rate regulation is currently under review and the outcome is uncertain.

---

[17] Exposure drafts are issued for discussion purposes prior to the issuance of a new accounting standard. The final standard frequently reflects comments on the exposure draft submitted by interested parties.

3 - REVENUE RECOGNITION

NP has traditionally recognized revenue under the billed method rather than the accrual method currently used by most utilities. It is now proposing to adopt the accrual method in 2006.

NP has asked me if its proposed adoption of the accrual method is consistent with established accounting and regulatory principles. The change in policy will give rise to the issue of what to do with the unbilled revenue at the end of 2005. This issue will be addressed in the next section.

BACKGROUND

Under the accrual method, revenues are recognized when services are provided. For rate setting purposes, rates are set so that the revenues from services provided in the test period equal the utility's revenue requirement for that period.

Under the billed method, revenues are recognized when services are billed to ratepayers. For rate setting purposes, rates are set so that revenues from services billed in the test period will equal the utility's revenue requirement for that period.

MATCHING OF REVENUES AND COSTS

The billed method results in a mismatching of revenues and costs that can affect rates. For example, assume that a utility is employing the billed method and services provided in the last month of each year are billed in the next year.

In the first year of the utility's operations, rates would be higher than under the accrual method. Rates would be set so that the utility would be able to recover its revenue requirement from its billed revenue. The billed revenue would cover only the 11 months of service billed in that year; while the revenue requirement would cover the costs of providing service for all 12 months. The revenues from services provided in the last month, but billed in the next year, would be ignored.

Under the accrual method, rates would be lower since they would be set so that the utility would be able to recover its revenue requirement from revenues over the 12 months that service is provided.

In the second year and every year thereafter, rates under the billed method would be set so that the revenue requirement for the year would be covered by revenues from service provided in the first 11 months of the current year plus the last month of the previous year. Unbilled revenue from the last month of the current year would be ignored.

In these years, the impact on rates from using the billed method rather than the accrual method would depend on the extent to which the unbilled revenue at the end of the year exceeds the unbilled revenue at the beginning of the year. If unbilled revenue is unchanged between the beginning and end of a year, use of the billed method in that year would have no impact on rates. However, increases in year-end energy sales and increases in rates would tend to increase the difference between the beginning and ending unbilled revenue. This would result in higher rates under the billed method.

At the end of each year, the unbilled revenue would represent the mismatch between revenues and costs. It would represent the cumulative difference between revenues from services provided and the costs of providing those services[18]. This difference would be used to cover revenue requirements in the next year.

CASH FLOW IMPACTS

The use of the billed method rather than the accrual method provides a cash flow benefit that reduces rates.

With the billed method, revenue requirements are met without considering the unbilled revenue at the end of the year. This results in a utility recovering its revenue requirement slightly faster than with the accrual method. The resulting increase in cash flow is approximately equal to the amount of the unbilled revenue.

The additional cash flow has reduced NP's invested capital. As discussed in Section 5, NP's rate of return on rate base is currently adjusted for differences between its invested capital and rate base. In effect, NP's return on rate base reflects its return on invested capital[19]. As a result, the reduction in invested capital reduces NP's return, and therefore, its rates.

As discussed in Section 5, NP is proposing to deduct from its rate base the unbilled revenue at the end of 2005 that has not been recognized in setting rates (i.e., unrecognized unbilled revenue or "UUR"). Once it fully moves to the asset rate base method, NP's return and revenue requirement will be reduced by the average UUR multiplied by its allowed rate of return on rate base. The effect is that the cash flow benefit of the UUR will continue to reduce rates.

NET IMPACT

The mismatching of revenues and costs under the billed method tends to increase rates in comparison to the accrual method. However, the increase in cash flow with the billed method reduces rates. The net effect will depend on a number of factors, such as the amount of any change in unbilled revenue.

[18] This assumes that actual revenues and costs are the same as the estimated amounts used in setting rates.

[19] This would not necessarily be the case in those periods in which the automatic adjustment formula is used to establish NP's allowed rate of return on rate base.

INDUSTRY PRACTICE

It is the normal practice for utilities to recognize revenue on an accrual basis for rate setting purposes. This is supported by a survey of Canadian electric and gas utilities that NP recently conducted and which has been included in Exhibit NP-3. Of the 23 utilities that responded to the question, all recognize their revenue on an accrual basis for rate setting purposes.

ACCOUNTING PRINCIPLES

Under GAAP, revenue should be recognized under the accrual method and not the billed method.

Section 1000 of the CICA Handbook, "Financial Statement Concepts" sets out the concepts underlying GAAP[20]. In discussing revenue recognition criteria, Section 1000 states:

> *Revenues are generally recognized when performance is achieved and reasonable assurance regarding measurement and collectibility of the consideration exists.*[21]

These conditions are met when NP provides electric service, not when it bills for the service. Supporting this interpretation is the following statement from Section 3400 of the CICA Handbook, "Revenue":

> *Revenue from service transactions and long-term contracts is usually recognized as the service or contract activity is performed…*[22]

In addition to the timing of revenue recognition, there is the issue of matching revenues and costs. With the billed method, revenues from services provided at the end of each year are recognized in the next year, even though the expenses related to the services are recognized in the current year.

Under GAAP, at least the direct costs of providing a service would be recognized as an expense in the same period that the associated revenue is recognized. For example, in discussing recognition criteria, Section 1000 states:

> *Expenses that are linked to revenue generating activities in a cause and effect relationship are normally matched with the revenue in the accounting period in which the revenue is recognized.*[23]

---

20 CICA Handbook; Section 1000 – Financial Statement Concepts; para. 1000.01.

21 CICA Handbook; Section 1000 – Financial Statement Concepts; para. 1000.47.

22 CICA Handbook; Section 3400 – Revenue; para. 3400.13.

23 CICA Handbook; Section 1000 – Financial Statement Concepts; para. 1000.51.

REGULATORY PRINCIPLES

In deciding between the billed and the accrual methods for rate setting purposes, the key regulatory principle is intergenerational equity. Under this principle, ratepayers in a given period should pay only the costs necessary to provide them with service in that period. They should not have to pay for any costs incurred to provide service to ratepayers in another period. Exhibit JTB-3 provides a more extensive discussion on the principle of intergenerational equity while Exhibit JTB-4 provides examples of where Canadian regulators have recognized this principle in setting rates.

The billed method results in a mismatching of revenues and costs. Revenues from services that are unbilled at the end of the year are used to cover the revenue requirement of the next year. This means that ratepayers are paying for costs to provide service in the following year, which is contrary to the principle of intergenerational equity[24]. However, in most years, it is unlikely that the net effect will be material since the revenue from services unbilled at the end of the previous year is used to reduce the current revenue requirement recoverable through rates.

With the accrual method, there is a proper matching of revenues and revenue requirement consistent with the principle of intergenerational equity.

CONCLUSION

NP's proposal to adopt the accrual method for recognizing revenue is consistent with industry practice, established accounting principles (i.e., GAAP), and established regulatory principles (i.e., principle of intergenerational equity).

---

[24] With unbilled revenue being included in taxable income, intergenerational inequity under the billed method will be increased.

4 - UNRECOGNIZED UNBILLED REVENUE

NP is proposing to shift from the billed to the accrual method of recognizing revenue for rate setting purposes in 2006. If its proposal is accepted, there will be a need to address the unbilled revenue at the end of 2005 that has not been recognized in setting rates (i.e., UUR).

NP is proposing:

- to use $9.6 million of the UUR to meet its revenue requirement in 2006; and
- that the PUB determine in a future order the disposition of the remaining $14.4 million in UUR.

NP has asked me whether its proposed treatment of the UUR in 2006 is consistent with established regulatory principles and what established regulatory principles should be considered in dealing with the remaining UUR subsequent to 2006.

BACKGROUND

The UUR will result from a mismatching of revenues and costs. It will represent cash from providing past services that was intended to cover future revenue requirements.

Up until now, the unbilled revenue at the end of each year has been used to reduce NP's revenue requirement recoverable through rates in the following year. With the proposed adoption of the accrual method in 2006, the unbilled revenue at the end of 2005 will not automatically be used to reduce NP's revenue requirement recoverable through rates in 2006, or in any other year.

NP has estimated that its UUR will effectively be $24.0 million. This reflects the total estimated amount of unbilled revenue at December 31, 2005 of $24.3 million, less an estimated amount of $295,000 in the Unbilled Revenue Increase Reserve ("Reserve").

In Order No. P.U. 36 (1998-99), the PUB ordered NP to establish the Reserve. It was intended to account for the impact of the revenue lag inherent in the billed method of revenue recognition in those months when customer rates change. The current balance in the Reserve represents revenue that has been recognized but not yet been billed to customers. In effect, it is the opposite of what the UUR will be – i.e., billed but not yet recognized as revenue. It is therefore appropriate to net the two amounts.

The build up of the UUR has occurred over at least the forty years since NP was created by an amalgamation of utilities. At the end of any year, including 2005, the unbilled revenue relates entirely to services provided in that year. However, the impact of the billed method on revenues has been equal to the change in unbilled revenue during the year. Therefore, the increase in revenues related to the UUR has occurred over the entire period that the billed method has been used in setting rates.

Based on NP's estimates, approximately $6.4 million[25] of the $24 million in the UUR will have arisen over the ten year period ending in 2005, and $12.9 million [26]over the twenty year period ending in 2005.

As a result of its agreement with the Canadian Revenue Agency ("CRA"), NP will be required to recognize the unbilled revenue at December 2005 as taxable income in equal instalments over a three year period beginning in 2006[27].

Recognizing the unbilled revenue as taxable income will not result in an increase in tax to the extent that the unbilled revenue is used to reduce the revenues NP receives from rates. Any reduction in revenues from rates will reduce taxable income and offset the increase due to including the unbilled revenue at December 2005 in taxable income.

NP is proposing to use $9.6 million of the UUR to reduce its revenue requirement in 2006. The $9.6 million represents the UUR that has built up over approximately the last 10 to 20 years. The disposition of the remaining UUR of approximately $14.4 million will be determined by the PUB in a future order. However, to the extent that the UUR is not used to reduce rates, it will remain a source of funding without cost. As discussed in the previous section, it will reduce NP's return and the revenue requirements it recovers from ratepayers.

If NP were to seek the $9.6 million through an increase in rates, it would require an additional $15 million in revenues. The difference between the $9.6 million and the $15 million ($5.4 million) would represent the increase in taxes associated with the revenues necessary to provide $9.6 million[28]. However, since the $9.6 million will be covered by recognizing a portion of the UUR, there will be no additional taxes. NP must pay the tax on the UUR at December 31, 2005 over three years, whether or not it recognizes any of the UUR for rate setting purposes.

$6,950,000 of the $9.6 million is to cover increases in NP's depreciation expense, while the remaining $3 million is primarily to cover one third of the income taxes on the unbilled revenue at December 31, 2005[29]. Therefore the ongoing amount of revenue requirement being covered by the recognition of the UUR is essentially $6,950,000 or $10.9 million after considering income taxes[30]. This represents approximately 2.5% of NP's 2006 revenue requirement.

---

25 The unbilled revenue at December 31, 1995 was $17.6 million ($24.0 million - $17.6 = $6.4 million).

26 The unbilled revenue at December 31, 1985 was $11.1 million ($24.0 million - $11.1 = $12.9 million).

27 There will be a difference between the unbilled revenue at December 31, 2005 and the UUR. The difference will be the balance in the Reserve, which is estimated to be $295,000.

28 This assumes a tax rate of 36.12%: $15 million – ($15 million * 36.12%) = $9.6 million.

29 A small amount (approximately $165,000) of the $3 million will cover the income taxes on the forecast additional revenue as a result of adopting the accrual method (i.e., $457,000).

30 This assumes a tax rate of 36.12%: $10.9 million – ($10.9 million * 36.12%) = $6.95 million.

Recognizing the UUR to meet its revenue requirements will reduce NP's cash flow and could have implications for its financial integrity. The recognition will not generate any cash but will displace cash from an otherwise necessary increase in rates. Based on its estimates for 2006, NP has concluded that its proposed disposition of the UUR in 2006 will not have materially adverse affects on its financial integrity and ability to raise capital.

REGULATORY PRINCIPLES

The key regulatory principles relevant to the issue of the UUR are the cost of service standard, the principle of intergenerational equity, the principle of rate stability and predictability and financial integrity. In at least some cases, these principles may conflict with each other.

The principles are discussed more extensively in Exhibit JTB-3.

COST OF SERVICE STANDARD

The cost of service standard states that a utility should be permitted to set rates that allow it the opportunity to recover its costs for regulated operations, including a fair rate of return on its investment devoted to regulated operations – no more, no less.

NP is proposing that the benefits of the UUR be used to reduce the revenue requirements recoverable from ratepayers. $9.6 million is to be used to reduce the revenue requirement in 2006 while the disposition of the remainder is to be determined by the PUB in a future order. In addition, any outstanding UUR will be used to reduce the return included in NP's revenue requirement[31].

NP's proposal to use the UUR for the benefit of ratepayers is in accordance with the cost of service standard. The UUR will represent cash from providing past services that was intended to cover future revenue requirements, rather than past revenue requirements. For the utility to keep any of the UUR for its benefit would result in the utility being provided an opportunity to recover more than its costs of providing regulated service.

INTERGENERATIONAL EQUITY

The principle of intergenerational equity states that ratepayers in a given period should pay only the costs necessary to provide them with service in that period. They should not have to pay for any costs incurred to provide service to ratepayers in another period.

---

[31] While NP continues to use its current method of establishing its allowed return on rate base, its return will be reduced because the UUR will continue to reduce its invested capital. Once NP fully adopts the asset rate base method, its return will continue to be reduced because the UUR will be deducted in calculating its rate base.

Ratepayers in one year tend to be the same as those in the next and an individual's usage generally doesn't vary that much from one year to the next. However, differences will tend to increase over time. Generally, the less time between the period in which ratepayers over pay and the period in which they receive the benefit of that overpayment, the less serious the breach of the principle of intergenerational equity.

The UUR will represent cash from the provision of past services intended to cover future revenue requirements Therefore, the principle of intergenerational equity would tend to support the use of the UUR to reduce revenue requirements as soon as is reasonable.

However, there is probably a significant difference between the customer base in 2006 and the customer base in the period prior to 1995. As a result, in deciding the period over which the UUR should be returned to ratepayers, intergenerational equity should only be a significant factor for the portion of the balance that arose over the last ten years to 20 years, approximately $6.4 million to $12.9 million.

Therefore, recognizing how the UUR was built up, amortizing $9.6 million of the UUR in 2006 is consistent with the principle of intergenerational equity. However, intergenerational equity should not be a major factor in deciding on the disposition of the remaining UUR.

Intergenerational equity is also an issue on a going forward basis. The unbilled revenue at the end of 2005 will be brought into taxable income over three years. In accordance with the principle of intergenerational equity, the income tax costs associated with the UUR should be recovered from the ratepayers that benefit from it. At a minimum, a sufficient amount of the UUR should be recognized in each of 2006, 2007 and 2008 so as to offset any increase in income taxes associated with the unbilled revenue at December 2005[32/33].

RATE STABILITY AND PREDICTABILITY

In accordance with the principle of rate stability and predictability, any use of the UUR to reduce revenue requirements should not negatively affect rate stability and predictability, and if reasonable, should contribute to it.

NP's proposed recognition of the UUR to cover ongoing costs (i.e. depreciation) in 2006 will defer a necessary rate increase of about 2.5%. However, with its current accounting policies and what it knows at the current time, NP believes it is unlikely that its proposed one year deferral will materially contribute to rate instability. Given fuel market volatility and the flow through of fuel prices through NP's Rate Stabilization Account, the proposal may even enhance rate stability.

---

32 There is a difference between the unbilled revenue at December 31, 2005 and the UUR. The difference is the estimated balance in the Reserve of $295,000.

33 Other considerations, such as rate stability, may affect the decision on the disposition of the remaining UUR.

FINANCIAL INTEGRITY

Two of the three established regulatory standards for a fair return are that the return should assure the financial integrity of the utility and be sufficient to allow it to attract the capital necessary to finance its operations (hereafter these two standards are jointly referred to as financial integrity). For example, in a recent generic hearing dealing with the cost of capital for eleven Albertan utilities, the Alberta Energy and Utilities Board ("AEUB") stated:

> *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.*[34 35]

In addition, Section 3 of the Electrical Power Control Act, 1994 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*
>
> …
>
> *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 …*

The above deals with establishing a fair return and not directly with issues such as the disposition of the UUR. However, the PUB should consider how the disposition of the UUR could affect NP's financial integrity, since it may affect the returns that NP should be allowed in order to maintain its financial integrity.

As indicated above, NP believes that its proposal to use $9.6 million of the UUR to meet its revenue requirement in 2006 will not jeopardize its financial integrity.

EXAMPLES OF REGULATORY PRACTICE

In a 1989 decision, the Canadian Radio-television and Telecommunications Commission ("CRTC") dealt with the issue of returning an amount to ratepayers through a reduction

---

[34] Alberta Energy and Utilities Board; Decision 2004-052 - Generic Cost of Capital**;** July 2, 2004; pg. 13.

[35] The three decisions referred to by the AEUB were the three decisions frequently referred to by rate of return experts: Northwestern Utilities v. the City of Edmonton [1929]; Federal Power Commission et al. v. Hope Natural Gas Company, 320 U.S. 591 (1944); and Bluefield Waterworks and Improvement Company v. Public Service Commission of the State of West Virginia et al., 262 U.S. 679 (1923).

in future rates. The telephone companies regulated by the CRTC recognized deferred taxes (i.e., income taxes payable in the future on account of current income) in determining their revenue requirement. As a result of a decrease in income tax rates, the amount the telecommunications companies had previously collected from customers to cover the deferred taxes (i.e., the deferred tax liability or "DTL") exceeded the amount of the deferred income taxes that they were expected to pay. As a result, the CRTC decided to have the excess returned to customers.

In determining the amortization period over which the excess would be used to reduce rates, the CRTC set out the following objectives which relate to last three of the four principles discussed above: inter-generational equity, rate stability and the financial integrity.

> *In choosing the appropriate amortization period, the Commission has attempted to reconcile three objectives that may, from time to time, conflict with each other.*
>
> *(1)The period should be short enough that subscribers quickly receive the benefit of the excess DTL since the excess was accumulated out of rates paid by subscribers in the past. In addition, a short amortization period increases the possibility that the same customers who were charged the excess amounts for income taxes will receive the tax credits.*
>
> *(2)The amortization period should not be so short as to lead to wide fluctuations. In particular, the Commission wishes to avoid a substantial rate increase when the amortization period ends and no further credits to the revenue requirements are available.*
>
> *(3)The excess DTL should be amortized over a period sufficiently long that the carriers' financial ratios are not adversely affected.*[36]

The Commission went on to state:

> *An individual carriers' circumstances may justify a different amortization period.*[37]

In the case of Bell Canada, B.C. Telephone, and NorthwesTel, the CRTC decided that the excess deferred tax liability should be amortized in equal monthly amounts over five years. However, in the case of Teleglobe, which had a smaller excess, the CRTC decided that the excess should be amortized in equal monthly amounts over a two-year period.[38]

---

[36] Canadian Radio-television and Telecommunications Commission; Telecom Decision CRTC 89-9; July 17, 1989; pg. 24-25.

[37] Canadian Radio-television and Telecommunications Commission; Telecom Decision CRTC 89-9; July 17, 1989; pg. 25.

[38] Canadian Radio-television and Telecommunications Commission; Telecom Decision CRTC 89-9; July 17, 1989; pg. 26.

Exhibit JTB-4 provides additional examples of where regulators have recognized the principles of intergenerational equity and rate stability and predictability in setting rates. In many of the cases, the regulators recognized that there was a trade-off between these two principles. In most of these cases, the regulators were dealing with an increase in future rates to allow for the recovery of a past cost. As a result, financial integrity was not a concern.

CONCLUSION

NP's proposed treatment of the UUR in 2006 is consistent with established regulatory principles.

- NP's recognition that the benefits of the UUR should flow to ratepayers is consistent with the cost of service standard.

- NP's proposal to use $9.6 million of the UUR to reduce its revenue requirement in 2006 is consistent with the principle of intergenerational equity, is not expected to result in any material rate instability and is not expected to materially jeopardize its financial integrity.

When the disposition of the remaining $14.4 million of UUR is addressed, consideration should be given to the principle of intergenerational equity, the principle of rate stability and predictability and the impact on NP's financial integrity.

In dealing with the remaining UUR, there are two aspects to the issue of intergenerational equity: the fact that the UUR arose from rates paid by ratepayers in the past and the fact that taxes on the UUR will have to be paid in 2007 and 2008.

- In dealing with the first, it can be argued that the remaining UUR arose from ratepayers at least 10 to 20 years in the past. Since there have likely been major changes in the customer base over the last 10 to 20 years, intergenerational equity should not be a major consideration.

- In dealing with the second, it should be recognized that ratepayers in 2007 and 2008 will have to pay a portion of the tax on the UUR, regardless of how the PUB decides to deal with the remaining UUR. Therefore considering only the issue of intergenerational equity, 2007 and 2008 should be allocated a portion of the UUR at least equal to the amount necessary to cover the taxes arising from the UUR in those years[39].

[39] Of course, after considering the principle of rate stability and predictability, the issue of financial integrity, and other possible relevant factors, the PUB may decide a different allocation is appropriate.

5 - ARBM ACCOUNTING POLICIES

In the future, NP will employ the Asset Rate Base Method ("ARBM"), as required by the PUB. The ARBM is a methodology for calculating the return included in a utility's revenue requirement. As part of the transition to the ARBM, NP is proposing the following changes to its regulatory accounting policies:

- Reduce its rate base by the amount of the UUR; and
- use book equity rather than regulated equity in calculating invested capital and the weighted average cost of capital ("WACC").

NP has asked me whether the changes it has proposed are appropriate in the context of the ARBM and what principles it should follow in any future review of its accounting policies related to the calculation of its rate base.

BACKGROUND

Technically, NP uses a return on rate base methodology. Its allowed return (i.e., cost of capital) is established by multiplying its rate base by its allowed rate of return on rate base. However, given the manner it which its allowed rate of return on rate base is calculated, NP's allowed return effectively reflects a return on invested capital methodology.

NP's allowed rate of return on rate base is determined by the following formula:

$$\frac{\text{Rate of Return on}}{\text{Rate Base}} = \left[\frac{\text{Invested Capital}}{\text{Rate Base}} * \text{WACC} \right] + \frac{\text{Z}}{\text{Rate Base}}$$

From a review of the formula, it can be seen that NP's allowed return reduces to its invested capital times WACC, plus or minus the Z factor. At the current time, most of the Z factor is accounted for by a reduction to recognize the cost of invested capital used to finance construction work in progress ("CWIP").

Changes to rate base that are not reflected in invested capital have no impact on NP's return. Any increase in NP's rate base is offset by a corresponding decrease in its allowed rate of return on rate base. This assumes that the allowed rate of return is being established within a general rate application ("GRA")[40]. However, this may not be the case for other years.

In a 2003 decision related to NP's last GRA, the PUB decided that NP should move to an asset rate base method:

[40] In these cases, the "Rate Base" in the formula is the same as the "Rate Base" to which the allowed rate of return produced by the formula is applied.

> *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.*[41]

Although not specifically defined in the decision, the "Asset Rate Base method" is assumed to be the return on rate base methodology described below.

ARBM OBJECTIVE

Under the cost of service standard, a utility should be provided an opportunity to recover its costs of providing regulated service, including a fair return on its investment devoted to regulated operations – no more, no less[42]. Therefore, the methodology for establishing a utility's allowed return, including the associated accounting policies, should be designed to provide this fair return.

The most common approach to calculating return is to use a return on rate base methodology. With this type of methodology, a utility determines its rate base, the average cost of financing a dollar of rate base (i.e., WACC) and multiplies the first amount by the second to establish the return to include in its revenue requirement.

The rate base should equal the total amount of the investments that are required to provide regulated operations and that must be financed. It is essentially equal to the amount of cash that the utility has had to pay out to provide regulated service but has not yet had an opportunity to recover through rates. It may also include allowed equity returns that the utility has not yet had an opportunity to recover through rates[43].

In some cases, a utility will have an opportunity to recover a cost through allowed rates before it is required to pay for the cost. This provides cash that can be used to finance regulated operations, without a cost to the utility. It reduces the investment that must be financed by the utility. As a result, these amounts should be deducted in calculating a utility's rate base[44]. For example, at the end of 2004, NP had a deferred income tax liability of $1.5 million. The liability represented amounts NP had been allowed an opportunity to collect through rates to cover income taxes that it had not yet been required to pay.

---

[41] Newfoundland and Labrador Board of Commissioners of Public Utilities; Order No. P.U. 19 (2003) - Newfoundland Power Inc. 2003 General Rate Application; June 20, 2003; pg. 71.

[42] For a discussion of the cost of service standard, see Exhibit JTB-3.

[43] For example, the cost of equity in the allowance for funds used during construction ("AFUDC") is included in the cost of the associated assets. A utility is allowed an opportunity to earn a return on the undepreciated cost of those assets (including AFUDC) once they are placed in service.

[44] An alternative approach that is frequently used is to treat the cash flow as a source of financing and include the amounts in the determination of WACC as zero cost capital.

There have been instances where utilities have used a return on invested capital methodology[45]. With this type of methodology, the focus is on the cost of the sources of financing rather than what must be financed. At least in theory, both the return on rate base and return on invested capital methodologies should produce the same fair return.

Whatever methodology is used, it should allow a utility the opportunity to recover the cost of financing its investments necessary to provide regulated service, including both the cost of debt and the cost of equity (i.e., a fair return). These investments would essentially consist of the prudently incurred costs that the utility has paid out but not yet had an opportunity to recover from ratepayers.

RATE BASE VS. INVESTED CAPITAL

Return on rate base and return on invested capital methodologies should produce the same returns because a utility's rate base should equal the invested capital necessary to finance its rate base. The rate base represents what a utility has to finance while invested capital represents the sources of financing.

Differences between a utility's rate base and its total invested capital can arise because a utility has investments not required to provide regulated services, at least not in the current period. Where an invested capital methodology is used, adjustments would normally be made for these differences. The following are the major reasons for the differences:

- CWIP is usually excluded from rate base because the assets are not currently used and required to be used in providing regulated service. The cost of financing these assets (i.e. the allowance for funds used during construction or "AFUDC") is usually capitalized and included in the cost of the associated assets.

- A utility may have investments related to non-regulated operations. For example, a utility may own the shares of a non-regulated affiliate. Since these investments are not used and required to be used to provide regulated service, they are excluded from rate base.

- A regulator may disallow investments related to regulated operations because they were not prudently incurred or are not used and required to be used to provide regulated service. For example, the amount of a purchase premium arising from the acquisition of a utility is usually excluded from rate base.

In the case of NP, the differences between its rate base and total invested capital should normally be small relative to its total rate base. The major difference for NP would be

[45] For example, Nova Scotia Power has been regulated using a return on equity methodology, a form of return on invested capital. However, in a 2005 decision, the Nova Scotia Utilities and Review Board ordered the utility to use a return on rate base methodology for its next rate application.

CWIP. However, being a distribution utility with short construction periods, NP's CWIP tends to be relatively small.

Differences in the calculated amounts of rate base and invested capital can also arise due to differences in how rate base items and invested capital are calculated. These differences usually relate to working capital items:

- Necessary working capital is usually based on a lead lag study that often addresses only cash operating expenses and the revenues related to those expenses.[46] It also attempts to reflect average daily balances while invested capital usually represents an average of the opening and year-end amounts of invested capital.

- Materials and supplies are sometimes determined by taking a monthly average of the estimated balances whereas invested capital usually represents an average of the opening and year-end amounts of invested capital.

NP'S PROPOSAL

NP is proposing to reduce its rate base by the amount of the UUR and to use book equity rather than regulated equity in calculating its invested capital and WACC.

UUR

NP is proposing to deduct the average UUR in the calculation of its rate base.

As discussed in the previous section, the UUR will represent cash from past services[47] intended to cover future revenue requirements. Until the UUR is used to reduce revenue requirements recoverable from rates, it will reduce the net investment that must be financed by NP. Therefore, it is appropriate to deduct the UUR from rate base.

EQUITY

NP is proposing to use book equity rather than regulated equity in the calculation of invested capital and WACC.

NP's book equity represents the amount of equity available to finance its rate base whereas the regulated equity in excess of book equity does not represent a source of funding. It is therefore appropriate to exclude the excess from the calculation of invested capital and WACC, and to use book equity rather than regulated equity.

---

[46] For example, in many cases, a lead lag study only recognizes receivables to the extent that they relate to the revenue required to cover cash operating expenses.

[47] Once the unbilled revenue is collected.

CONCLUSION

In calculating the allowed return included in its revenue requirement, NP is moving to the ARBM from a methodology that effectively reflects a return on invested capital methodology. At least in theory, the two methods should produce the same results since the rate base should equal the invested capital necessary to finance regulated operations.

NP is proposing to deduct the UUR from its rate base and use book equity rather than regulated equity. These proposed changes in accounting policy are appropriate in the context of the ARBM. The UUR reduces the investment that must be financed by NP while the difference between regulated and book equity is not a source of financing for NP's operations.

In any future review of accounting policies related to its rate base, NP should ensure that its policies:

- Include in rate base all of its investments necessary to provide regulated service. These investments would essentially include all cash payments and allowed equity return that the utility has not yet had an opportunity to recover through rates.

- Where the utility has had an opportunity to recover costs from ratepayers before it has had to pay out the cash for those costs, deduct the amounts from rate base.[48]

[48] Alternatively, NP may include the amounts in the calculation of WACC as zero cost capital.

RESUME - JOHN T. BROWNE

Summary:

John Browne has been providing costing and regulatory consulting services to utilities and telecommunications companies for 21 years. Prior to establishing his own practice six years ago, he was a consultant with Deloitte and Touche LLP, the last seven years as a partner.

He has directed and worked on a wide range of studies for regulated companies dealing with accounting and cost allocation principles, cost of service determination, product costing/pricing, rate of return, capital structure, and methods of regulation.

He has appeared as an expert witness before the Canadian Radio-television and Telecommunications Commission, Canadian Transport Commission, the Alberta Public Utilities Board / the Alberta Energy and Utilities Board, the Manitoba Public Utilities Board, Newfoundland and Labrador Board of Commissioners of Public Utilities and the Nova Scotia Board of Commissioners of Public Utilities.

Education / Professional Qualifications:

- Bachelor of Commerce - Queen's University
- Master of Arts (Economics) - Queen's University
- completed the course work and comprehensive exam requirements of the doctorate program in economics
- Chartered Accountant

Committees/ Publications

Mr. Browne was Chairman of the Canadian Institute of Chartered Accountants (CICA) Study Group that produced the CICA research report “Financial Reporting By Rate Regulated Enterprises”

He co-authored the Deloitte & Touche publication “Basics of Canadian Rate Regulation” and authored the Deloitte & Touche monograph “The Contractual Pitfalls of Relying on GAAP”.

Key Clients:

Mr. Browne's major clients have included: Newfoundland Power Inc., Nova Scotia Power Inc., New Brunswick Power Corporation, Hydro Quebec, Ontario Hydro, Manitoba Hydro, SaskPower, Edmonton Power, Ottawa Hydro, Canadian Electricity Association, Ontario Energy Board, Atco Gas, Enbridge, Newfoundland Telephone Company Ltd., Bell Canada, Manitoba Telephone System, Saskatchewan Telecommunications, AGT/TELUS, Teleglobe, Telesat Canada, Southwestern Bell Telephone Company, New York Telephone and The Telecommunication Authority of Singapore.

Selected Assignments:

- Completed a survey of Canadian regulators to determine what they viewed as their objectives and how they interpreted those objectives.

- Provided a one-day workshop on regulatory issues to an electric utility with both distribution and transmission operations. The key focus was on performance-based regulation and affiliate transactions.

- Prepared and delivered a half day seminar on accounting for the effects of rate regulation for a Canadian electric utility.

- Assisted Hydro-Québec by researching issues related to the determination of rate base for a first time rate application and preparing a report that recommended how the utility's rate base should be established at its initial rate hearing.

- Researched and analysed the issue of a deferral plan for the introduction of a new plant into rate base. Prepared evidence on the issue for Nova Scotia Power and appeared as an expert witness. Subsequently prepared evidence and appeared as an expert witness on changes to the deferral of the costs on the plant due to changes in circumstances.

- Prepared a report for Hydro-Québec TransÉnergie that addressed regulatory issues related to the transfer of assets into the utility's regulated rate base.

- Researched, analysed and presented a recommendation that an electric utility should be allowed to defer tax costs so that the utility could avoid a rate increase followed by a rate decrease.

- Reviewed various regulatory issues as part of the due diligence for the Altalink's purchase of TransAlta's transmission assets in Alberta.

- Provided a written opinion for Nova Scotia Power on its regulatory treatment of amounts related to an income tax dispute. The report dealt with past taxes that had not been recovered in allowed rates and future taxes that may not be payable.

- Prepared a report for SaskPower, an integrated electric utility, that addressed the issues related to including or excluding non-core operations from the scope of rate regulation and the regulatory implications for any dealings between these types of operations and its core regulated operations.

- Provided a written opinion for Newfoundland Light & Power on accounting and regulatory issues related to future employee benefits and the company's hydro production equalization reserve. The opinion was included in the company's rate submission.

- Researched and analysed the issues of phase-in and risk sharing for Edmonton Power's Genesee plant and prepared a recommendation that was submitted to the utility's regulator. Expert testimony was also provided.

- Completed a study for New Brunswick Power that identified and evaluated the options for restructuring the electric power industry in New Brunswick and privatizing all or part of the Company. As part of the assignment, reviewed the developments occurring throughout the world with a focus on North America.

- Provided a written opinion for Nova Scotia Power that addressed whether its proposal to change from market value to market related value in determining its pension expense was consistent with generally accepted accounting principles and established regulatory principles.

- Assisted a diversified energy company by reviewing its transfer prices to and from regulated operations and recommending changes.

- Prepared evidence for a hearing before the Newfoundland Board of Commissioners of Public Utilities that dealt with regulatory control, regulatory reporting, return for a public sector utility and the accounting issues of inter-corporate charges and employee future benefits.

- Prepared a report that dealt with the corporate charges from a parent company to a regulated gas utility. The report evaluated the consistency of the charges with the past decisions of the OEB and its Affiliate Relationships Code for Gas Distributors. The report was submitted to the OEB.

- Assisted Ontario Hydro Services Company (now Hydro One), in understanding its regulatory options by researching and providing advice on a number of regulatory issues related to transfer pricing, structural organization, accounting for income taxes, relationships with affiliated companies, performance-based regulation, etc.

- Researched and evaluated options for the regulation of Nova Scotia Power. A recommendation was submitted to the utility's regulator and expert testimony provided.

- Analysed the issue of the appropriate accounting and regulatory treatment of Nova Scotia Power's defeasance program. Prepared evidence and appeared as an expert witness on the issue.

- Researched and evaluated the appropriateness of Newfoundland Power Inc.'s inter-corporate charges. A recommendation with support was submitted to the Newfoundland and Labrador Board of Commissioners of Public Utilities.

- Prepared an opinion for SaskPower on the proper accounting for its capital reconstruction charge that recognized its position as an electric utility with rates set on a cost recovery basis.

- Completed a study and recommended a cost of equity rate for Edmonton Power for each of the years 1985, 1986, 1987, 1988, 1989, 1993 and 1996. The reports for 1985, 1986 and 1996 were included in the Company's rate submissions to the Public Utilities Board of Alberta / Alberta Electric and Utility Board and expert testimony was provided at a public hearing.

- Assisted the Ontario Energy Board Staff in identifying the parameters for a costing study to be completed by a gas distribution utility regulated by the Board.

- Advised New Brunswick Electric Power on accounting and regulatory issues related to reserve accounts in the regulatory environment.

- Assisted New Brunswick Electric Power in addressing various accounting issues related to its first rate hearing.

- Researched and analysed the methodology for calculating working capital for Edmonton Power. Prepared evidence on the issue and appeared as an expert witness.

- Researched, analysed and prepared a recommendation on the issue of whether Nova Scotia Power should recover a purchase premium paid by the utility on the purchase of a distribution utility.

- Completed a study to establish an appropriate capital structure for Edmonton Power and prepared a report recommending an appropriate capital structure for regulatory purposes that formed part of the utility's 1996 submission to the Alberta Energy and Utility Board.

- Advised Manitoba Hydro on the development of appropriate financial targets and prepared evidence on the issue for submission to the utility's regulator. The assignment required researching and analysing the issue of appropriate financial targets for a government owned utility.

- Researched and analysed various issues dealing with the introduction of price-cap regulation for a telecommunications company and prepared position papers for the company.

- Analysed and recommended an appropriate capital structure for Ottawa Hydro (a municipally owned utility) in the context of the restructuring of the Ontario electric power industry.

- Reviewed Manitoba Hydro's financial targets and recommended changes to those targets in light of the changes in the electric utility industry, especially the introduction of competition. The assignment included a review of trends in the electric utility industries of Canada, the United States and the United Kingdom and the implications for a government owned utility.

- Assisted a government owned telecommunications company in a review of the methods by which it could be regulated. The assignment included a review of its changing financial requirements, and the need for the company to improve its equity position.

- Advised the business unit of a major telecommunications company on the appropriate basis for establishing the transfer prices to be charged to other business units within the company.

- Evaluated the ability of a telecommunications company's existing costing systems to meet CRTC Phase III costing requirements and provided an opinion on whether the methodology would be defensible.

- Prepared a report recommending the costing principles to be used in the regulatory reporting of a telecommunications company in the Maldives and assisted in implementing those principles.

accounting guideline
AcG-19
disclosures by entities subject to rate regulation

This Guideline is to be read in conjunction with the Introduction to Accounting Guidelines contained in the CICA Handbook – Accounting.

May 2005

TABLE OF CONTENTS **Paragraph**

PURPOSE AND SCOPE

1 This Guideline presents the views of the Accounting Standards Board on certain aspects of the disclosure and presentation of information in the financial statements of entities providing services or products for which customer rates are established, or subject to approval, by a regulator or a governing body empowered by statute or contract to set rates. The objective is to ensure that financial statement users are better informed about the existence, nature and effects of all forms of rate regulation.

2 The requirements in this Guideline supplement those found elsewhere in the CICA Handbook – Accounting, as they pertain to rate-regulated operations.

3 This Guideline does not address recognition and measurement issues associated with the accounting for rate-regulated operations, and applies regardless of the accounting policies selected by an entity for its rate-regulated operations. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES, paragraph 1100.34, indicates that an entity is not required to apply that Section to the recognition and measurement of assets and liabilities arising from rate regulation, pending completion of a separate project on rate-

regulated operations, which is currently underway.

DISCLOSURE

Principles

4 Rate regulation can affect both the revenue-generating ability of an entity and the period in which its revenues are earned, and may, in certain circumstances, result in the creation of material economic benefits and obligations. It is, therefore, an important consideration in evaluating the financial performance of entities with rate-regulated operations.

5 To meet the needs of financial statement users, entities subject to rate regulation should disclose general information facilitating an understanding of the nature and economic effects of rate regulation, as well as additional information on how rate regulation has affected the entity's financial statements. The information should be presented in such a manner as to enable a clear understanding of these effects.

General information on rate regulation and its economic effects

6 An entity subject to rate regulation should disclose general information useful to an understanding of the nature and economic effects of rate regulation, including, at a minimum, the following:

(a) the fact that the entity is subject to rate regulation, and a description of the nature and extent of the rate-regulated operations; and

(b) for each set of operations subject to a different rate-setting authority or type of regulation:

(i) the identity of the rate-setting authority and, if it meets the definition of a related party (see RELATED PARTY TRANSACTIONS, Section 3840), a statement to this effect, together with an explanation of why this is the case; and

(ii) the process by which the entity's rates are approved, as well as a description of the type of regulation in effect, and information providing a basic understanding of how it has been applied. For example, in the case of cost-of-service regulation, this information would include the allowed rate of return, and for performance-based regulation it would include the approved formula for rate increases and how often the formula is reviewed.

Additional information on the financial statement effects of rate regulation

7 Rate regulation may cause an entity to account for a transaction or event differently than it would in the absence of rate regulation. Such differences in accounting may result from the application of GENERALLY ACCEPTED ACCOUNTING PRINCIPLES, paragraph 1100.34, or other Sections that require or permit entities subject to rate regulation to recognize or measure an item differently from other entities (see CONSOLIDATED FINANCIAL STATEMENTS, Section 1600; PROPERTY, PLANT AND EQUIPMENT, Section

3061; INCOME TAXES, Section 3465; and DISPOSAL OF LONG-LIVED ASSETS AND DISCONTINUED OPERATIONS, Section 3475).

8 When rate regulation has affected the accounting for a transaction or event, the entity should state this fact and disclose additional information about the effect on its financial statements. This information should include, at a minimum, the following:

(a) the specific financial statement items affected;

(b) for each item, how it has been reflected in the financial statements, as well as:

(i) the rationale for this treatment, including information about either the supporting regulatory action, for example, issuance of a final rate order or approval to accumulate amounts pending final disposition at a later date (the date being disclosed, when known), or the expectations of the entity regarding future regulatory actions; and

(ii) how it would have been reflected in the absence of rate regulation;

(c) when a separate asset or liability has been recognized solely as a result of the effects of rate regulation:

(i) the carrying amount of the asset or liability, as at the most recent balance sheet date, and the balance sheet line item that includes it when it is not otherwise evident;

(ii) the income statement effect of such recognition for the current period;

(iii) the remaining period over which the carrying amount of the asset is expected to be recovered or the liability is expected to be settled;

(iv) a description of the regulatory risks and uncertainties affecting the eventual recovery of the asset or settlement of the liability and its timing, consistent with MEASUREMENT UNCERTAINTY, Section 1508; and

(v) when the regulator does not include a return on investment in the rate base for the asset during its recovery period, a statement to that effect; and

(d) when accounting for the effects of rate regulation has been discontinued since the last financial statements issued, a statement to that effect, together with the reasons for the discontinuance and identification of the rate-regulated operations affected.

9 The financial statement note providing the information required by paragraph 8(a) should make reference to any other note containing the information required by paragraphs 8(b) and 8(c).

PRESENTATION

10 Assets and liabilities, including those recognized as a result of the effects of rate regulation, should be offset only when specifically permitted or required by another Section or Guideline.

TRANSITIONAL PROVISIONS

11 This Guideline is effective for fiscal years ending on or after December 31, 2005.

12 The information to be disclosed under paragraph 8(c)(ii) is not required for comparative information for periods prior to the effective date of this Guideline.

ILLUSTRATIVE EXAMPLE

This material is illustrative only.

This example illustrates how certain of the disclosure requirements specified in this Guideline might be applied in a particular situation. Matters of principle relating to particular situations should be decided in the context of this Guideline. The example relates only to the requirements of paragraph 8 of the Guideline. It does not show the disclosures required by the remainder of the Guideline, or other disclosures required by generally accepted accounting principles. The financial statement items included in the example are particularly relevant to utilities in the gas or electricity industries. However, since the primary purpose of the example is to illustrate the extent of the disclosures required by the Guideline, and to indicate how a tabular format may be used, it has relevance for all entities subject to rate regulation.

RRO Inc.
Notes to the Consolidated Financial Statements (extract)

Note 2: Financial statement effects of rate regulation

The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event. Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods, that are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting process.

Regulatory assets and liability

	20X2	20X1	Remaining recovery / settlement period (years)
Year ended December 31 ($ millions)			
Regulatory assets			
Recoverable losses on debt retired prior to maturity	$ 11	$ 8	14-20
Recoverable storm costs (a)	5	—	5
Purchased power cost variance	—	37	N/A
Total regulatory assets	$ 16	$ 45	
	===	===	
Regulatory liability			
Purchased power cost variance	$ 26	—	1
Total regulatory liability	$ 26	—	
	===	===	

(a) The rate base does not include an allowance for a return on investment for this item.

As prescribed by a regulatory rate order, gains and losses on debt retired prior to the date of maturity are included in allowed rates on a gradual basis, over the period from the retirement date to the original maturity date of the debt. Since it is expected that the long-term application of this regulatory policy will result in these gains and losses being refunded or recovered through customer rates in their entirety, they are recognized as a regulatory liability or asset in the year the debt is retired, with a corresponding charge or credit to income. The regulatory liability or asset is amortized and included in operating results on an annuity basis over the same period as that approved for rate-setting purposes. In the absence of rate regulation, generally accepted accounting principles would require the inclusion of such gains and losses in operating results of the year in which the debt is retired. In 20X2, $3 million (20X1 — $4 million) in losses on debt retired prior to the date of maturity was recognized as a regulatory asset, and the amortization of previously capitalized amounts totalled $1 million (20X1 — $1 million). Consequently, operating results are $2 million (20X1 — $3 million) higher than would have been the case in the absence of rate regulation. The regulatory asset is presented net of accumulated amortization as at December 31, and is included in recoverable debt costs.

In 20X2, RRO Inc. incurred storm costs amounting to $5 million. The regulator has issued an order requiring the exclusion of these costs from the determination of customer rates until their final rate treatment is decided in the next rate hearing (scheduled for 20X3). The Company intends to seek, and expects to receive, approval for recovery of the costs through future rates over a five-year period commencing in 20X3. Accordingly, the costs have been recognized as a regulatory asset to be amortized over the same period. In the absence of rate regulation, generally accepted accounting principles would require that RRO Inc. include such costs in operating results of the year in which they are incurred. The regulatory asset is included in other recoverable costs.

Purchased power costs are included in allowed rates on a forecast basis. For rate-setting purposes, differences between forecast and actual purchased power costs in the rate year are held until the following year, when their final disposition is decided. RRO Inc. recognizes purchased power cost variances as a regulatory asset or liability, based on the expectation that amounts held from one year to the next for rate-setting purposes will be approved for collection from, or refund to, future customers. The regulatory liability (20X1 — asset) represents the excess of forecast over actual (20X1 — actual over forecast) purchased power costs. In the absence of rate regulation, generally accepted accounting principles would require that actual purchased power costs be recognized as an expense when incurred. In this case, operating results for 20X2 would have been $26 million higher (20X1 — $37 million lower). The regulatory liability (20X1 — asset) is included in refundable purchased power charges (20X1 — recoverable purchased power costs).

For certain of the regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate-setting purposes. For example, RRO Inc.'s treatment of purchased power costs is dependent on the continued use of an automatic adjustment mechanism for regulatory purposes, and would require reconsideration if the regulator decided to discontinue the use of this mechanism or require the Company to absorb cost variances in a particular year. Similarly, there is a risk that the regulator may disallow a portion of the storm costs incurred in 20X2 for recovery through future rates, or disagree with the proposed recovery period.

Other items affected by rate regulation

As prescribed by a regulatory rate order, income tax expense is recovered through customer rates based on the taxes payable method. Therefore, rates do not include the recovery of future income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. RRO Inc. has not recognized future income taxes, as it is expected that when these amounts become payable, they will be recovered through future rate revenues. Generally accepted accounting principles require the recognition of future income tax liabilities and future tax assets in the absence of rate regulation.

The regulator permits an allowance for funds used during construction (AFUDC), based on RRO Inc.'s weighted average cost of capital, to be included in the rate base. AFUDC is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated over future periods as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFUDC component, will be approved for inclusion in future customer rates. Since AFUDC includes not only an interest component, but also a cost-of-equity component, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

REGULATORY PRINCIPLES

Regulators must review and set rates in accordance with their empowering legislation. However, this legislation seldom contains detailed guidance on how to set rates and often states little more than that rates must be just and reasonable.

The lack of detailed guidance means that regulatory boards not only have the opportunity to exercise a significant amount of judgment in setting or approving rates, they are required to so. To assist them in exercising their judgment, they frequently refer to established regulatory principles to guide them in determining what is just and reasonable in a particular case.

No single authority sets regulatory principles. Instead, principles become established through their general acceptance by regulators, and in some cases, reflect court decisions. Unfortunately, the principles may sometimes be in conflict and tradeoffs are required.

In the context of the issues on which NP has requested an opinion, the following principles are relevant:

- just and reasonable;
- cost of service standard;
- prudence standard;
- fair return;
- used and required to be used;
- intergenerational equity; and
- rate stability and predictability.

JUST & REASONABLE

The primary regulatory principle, and the one most likely to be incorporated into regulatory legislation, is that rates should be just and reasonable. "Just and reasonable" applies to both ratepayers and regulated entities. It requires a weighting of the legitimate interests of both parties.

This principle is consistent with the declared policy of the Province of Newfoundland and Labrador. For example, paragraph 3 of the "Electric Power Control Act, 1994" states that it is the declared policy of the province that the rates to be charged, either generally or under specific contracts, for the supply of power within the province should be reasonable and not unjustly discriminatory.

Unfortunately, "just and reasonable" is a vague and subjective concept. It provides an overall direction to regulators but little specific guidance.

COST OF SERVICE STANDARD

At the heart of rate regulation is the cost of service standard, sometimes referred to as the revenue requirement standard.

Under this standard, a regulated entity is permitted to set rates that allow it the opportunity to recover its costs for regulated operations, including a fair rate of return on its investment devoted to regulated operations – no more, no less.

It's important to note that this standard only gives the entity the opportunity to earn a fair return; it does not guarantee it. In most cases, rates are set prospectively, based on anticipated future costs. If the entity over-recovers, it normally keeps the excess. If it under-recovers, it bears the deficiency.

The cost of service standard is consistent with what is expected to occur in a competitive market, where the prices for goods and services tend to equal the cost of providing them, including a fair return. This is important since it is often argued that rate regulation is a proxy for competition[1] and it tends to be withdrawn where there is adequate competition to protect ratepayers.

The standard also reflects fairness and the necessity to offer adequate incentives for providing regulated services:

- In fairness, an entity's investors should have the opportunity to recover their costs, including a fair return, just as they would if they were to invest in a non-regulated entity of similar risk. However, ratepayers should not have to provide investors with the opportunity to earn more than they could expect from investing in non-regulated operations.

- From an incentive viewpoint, unless investors have a reasonable opportunity to recover their costs, it will be difficult to attract the investment necessary to provide regulated operations. However, the opportunity to recover costs, including a fair return, should provide an adequate incentive to attract those funds.

The cost of service standard is applicable to all regulatory methodologies, including performance-based methods such as price cap regulation. A regulated utility may earn more or less than a fair return, and performance based methods increase the possibility of realized earnings deviating from a fair return. However, the issue is that a regulated

---

1 For example, in a 2001 decision the Ontario Energy Board ("OEB") stated: *The Board notes that the general role of the regulator is to act as a proxy for competition….* (OEB; ; RP-2001-0032; December 13, 2002 para. 5.11.49)

entity should have a reasonable opportunity to earn a fair return, which implies that the possibilities of under and over earning are offsetting[2].

The cost of service standard is consistent with the Newfoundland and Labrador Public Utilities Act. For example, paragraph 80 states:

> *(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 …*
>
> *(2) The return shall be in addition to those expenses that 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.*
>
> *(3) Reasonable payments each year to former employees of a public utility who have retired and are receiving payments of supplemental income from the public utility are expenses that the board may allow as reasonable and prudent and properly chargeable to the operating account of the public utility. …*

PRUDENCE STANDARD

The prudence standard modifies the cost of service standard. Under this standard, ratepayers should be charged only for prudently incurred costs. This recognizes the fact that regulated entities have a responsibility to manage themselves in a prudent manner.

Deciding what is prudent is done by determining what a reasonable person would have done in a similar situation. This should not be done in hindsight. A regulated entity's management can be expected to rely only on information reasonably available to it when it makes its decision.

It’s generally assumed that management has acted prudently unless evidence exists to the contrary.

In a recent decision, the Ontario Energy Board (“OEB”) set out four principles that are reflective of the common interpretation of the prudence standard:

- *Decisions made by the utility’s management should generally be presumed to be prudent unless challenged on reasonable grounds.*
- *To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.*

---

2 The expected rate of return should equal a fair rate of return where the expected rate of return is equal to the average of the possible rates of return weighted by the probability of their occurrence.

- *Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.*

- *Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.*[3]

FAIR RATE OF RETURN

Under the cost of service standard, a regulated entity should have an opportunity to recover its costs for regulated operations, including a fair rate of return. To be considered fair, the return must be:

- Commensurate with returns on investments of similar risk;

- Sufficient to assure financial integrity; and

- Sufficient to attract necessary capital.

The first standard is consistent with the economic definition of the cost of equity and the goal of treating equity investors fairly. From an economic perspective, the cost of making an investment is the return foregone by not investing in an alternative investment of similar risk. In fairness, investors should have the opportunity to earn a return commensurate with what they could expect to earn from non-regulated investments of similar risk.

The second and third standards reflect both investor and customer interests. A regulated entity must be financially viable and have adequate returns to attract necessary capital if it is to be able to service ratepayers. Generally, if the first standard is met, so will the others.

The basis for these criteria is found in two US Supreme Court decisions frequently quoted in regulatory proceedings:

- Bluefield Water Works & Improvement Company v. Public Service Commission of the State of West Virginia et al. (262 US 679, 1923); and

- Federal Power Commission et al. v. Hope Natural Gas Co. (320 US 591, 1944).

---

[3] OEB; Enbridge Consumers Gas Distribution Inc., RP-2001-0032; December 13, 2001; para. 3.12.2.

The first standard was also set out by the Supreme Court of Canada (in Northwestern Utilities Limited v. The City of Edmonton and Alberta Public Utilities Board; 1929, SCR 186, 193), which defined a fair return as meaning:

> *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.*

USED AND REQUIRED TO BE USED

Under this standard, customers should pay only for the cost of those assets that are used and required to be used, to provide them with service.

This principle is applicable to the case of a diversified company with both regulated and non-regulated operations. The customers of the regulated operations should not be required to pay for assets used to supply non-regulated services.

The principle has also been applied to assets acquired for regulated operations. Regulators have denied the recovery and/or return on assets that were acquired for regulated operations, but are not currently required to provide service.

Regulators usually use a broad interpretation of "used and required to be used." For example, in the electric power industry, it includes reserve capacity and recognizes the discrete nature of economically sized capital additions, where the most efficient capital increments may result in capacity initially exceeding what is required by existing demand.

The used and required to be used standard can't be applied in isolation but only within the framework of the cost of service standard. For example, because of the used and required to be used standard, an entity may be unable to recover the cost and/or full return on some assets. If the entity is limited to a fair return on its remaining assets, it won't have an opportunity to earn a fair return on its investment in regulated operations.

Consistent with the cost of service standard, the regulator must increase the entity's allowed return to give it the opportunity to earn an expected return that meets the standards for a fair return. The expected return is the probability weighted average return – that is, the average of the possible returns, where each possibility is weighted by the probability that it will occur.[4/5]

---

[4] For example, if there is a 40% probability of an 8% return, and a 60% probability of a 12% return, the expected return is 10.4%: (8% x 40%) + (12% x 60%) = 10.4%.

Because of this, a regulated entity may be allowed to recover the cost of assets that don't meet the used and required to be used standard. Instead of compensating an entity for the possibility that assets may not be used and required to be used (a possibility that may never occur), the regulator may allow it to recover the cost of assets that are not used and required to be used if such a situation occurs.

INTERGENERATIONAL EQUITY

The principle of intergenerational equity deals with how the cost of service should be recovered from ratepayers. Under this principle, ratepayers in a given period should pay only the costs necessary to provide them with service in that period. They should not have to pay for any costs incurred to provide service to ratepayers in another period. This principle is consistent with setting just and reasonable rates within each period.

For example, a regulated entity is usually not allowed to earn a return on projects under construction. It's incurring this cost to provide service to future ratepayers, not ratepayers in the current period. Instead, the return is capitalized and recovered through depreciation over the period in which the assets are used to provide service.

Combined with the cost of service standard, the principle of intergenerational equity requires that rates within a period should cover the costs of providing service in that period.

This principle's importance depends on the periods involved. Ratepayers in one year tend to be the same as those in the next and an individual's usage generally doesn't vary that much from one year to the next. Having ratepayers in one year pay more as a result of costs incurred to provide service in the previous year would not be as serious a breach of this principle as it would be if they had to pay more because of service provided to ratepayers 10 years earlier. If costs can't be recovered in the period for which they were incurred, it's generally best to recover them in a period as close as possible to the one for which they were incurred.

RATE STABILITY AND PREDICTABILITY

Another principle that deals with how the cost of service should be recovered is the principle of rate stability and predictability. It requires rates to remain stable and predictable – at least to the extent practical.

---

[5] It isn't enough that the increase in allowed return reflects the expected cost of investments being deemed as neither used nor required to be used. This approach will increase the potential variability in the entity's earnings and, therefore, its risk. As a result, the entity's allowed return should be further increased to reflect this risk, should it be material.

This principle recognizes that it is usually easier for ratepayers to deal with gradual and predictable rate increases. It may justify smoothing out changes in rates to avoid sharp rate climbs or temporary fluctuations.

The principle's intent is to establish only when costs are recovered, not the amount actually recovered. In practice, it does affect the amounts recovered because the timing of cost recovery affects financing costs. Where costs are deferred, the deferred amount must be financed, and regulated entities are entitled to recover the additional financing costs under the cost of service standard.

The principle of rate stability and predictability may require costs to be collected from ratepayers in periods other than those for which they were incurred. Therefore, it is inconsistent with the principle of intergenerational equity. Despite that, it’s justified because it recognizes the adverse impact where ratepayers must adjust to significant rate increases or short-term rate fluctuations.

As time passes, the makeup and usage of a customer group changes. Therefore, the longer the period that costs are deferred, the more serious the breach of the intergenerational equity principle. As a result, when the principle of rate stability and predictability is applied, cost deficiencies should be recovered over as short a period as is reasonable, so the customer group that eventually pays for the costs is similar to the one benefiting from the costs. Similarly, if, to avoid a sharp rate increase, costs are recovered before a period for which they will be incurred, the intervening period should also be as short as reasonably possible.

REGULATORY PRACTICE

This exhibit presents examples of where regulators have recognized the principles of intergenerational equity and rate stability and predictability in setting rates. In most of the cases, there was a conflict between the two principles that the regulators were required to balance.

NEWFOUNDLAND AND LABRADOR BOARD OF COMMISSIONERS OF PUBLIC UTILITIES ("PUB")

In a recent decision dealing with the rate stabilization plan ("RSP") of Newfoundland and Labrador Hydro, the PUB recognized the importance of the principles of intergenerational equity and rate stability and predictability, and that a trade-off between these two principles can arise:

> *In considering this issue, the Board has to take into account the effect on rates of recovering some of the existing plan balance in the test year combined with its decision to rebase fuel at forecast prices. While lower RSP balances should accumulate as a result of recovering more of the fuel price in the actual base rate, the increase in base rates will be higher than that originally proposed by NLH. Recovering the RSP balance as proposed by NLH will mean even higher rates for both retail and industrial customers.*
>
> *In addition to considering the impact of all costs on electricity rates to consumers, the Board has to balance the issue of trying to match recovery of costs with the period in which these costs were incurred, sometimes referred to as an inter-generational equity issue. This issue was raised by several of the expert witnesses, in particular Mr. Bowman and Dr. Wilson. Although costs should normally be recovered over the period in which they are incurred, the Board also has to balance this goal with the impact on ratepayers of this kind of matching recovery.*[1]

NOVA SCOTIA UTILITIES AND REVIEW BOARD ("NSUARB")

As a result of a tax reassessment covering the years 1998 through 2002, Nova Scotia Power Inc. ("NSPI") was required to pay additional income taxes. The additional taxes plus related interest payments amounted to approximately $150 million (i.e., s. 21 tax costs).[2]

---

[1] PUB; Order No. P.U. 7 (2002-2003) re: Newfoundland & Labrador Hydro General Rate Review; June 7, 2002; pg. 87.

[2] NSUARB: NSUARB-NSPI-P-881 2005 NSUARB 27 re: Nova Scotia Power Incorporated; para. 170.

The NSUARB decided that the s. 21 tax costs should be recoverable through rates[3]. In deciding the amortization period over which the costs would be included in rates, the NSUARB indicated that the primary considerations were intergenerational equity and rate stability. Its decision to defer the amortization for two years and then amortize the cost over 8 years reflected a trade off between the two principles:

> *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.*
>
> …
>
> *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.*
> …
>
> *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.*[4]

PUBLIC UTILITIES BOARD OF MANITOBA ("MPUB")

In a 2003 decision dealing with the Gladstone, Austin Natural Gas Co-Op Ltd., the MPUB indicated the importance of rate stability and intergenerational equity:

---

[3] NSUARB: NSUARB-NSPI-P-881 2005 NSUARB 27 re: Nova Scotia Power Incorporated; para. 196.

[4] NSUARB: NSUARB-NSPI-P-881 2005 NSUARB 27 re: Nova Scotia Power Incorporated; para. 197 - 200.

The Board is of the view that gas sales forecast, diversion revenues, unit rates and fuel requirements are reasonable. The Board considers the requested Commodity Sales Rate appropriately reflects and balances the three elements considered to be important by the Board: prevailing market prices, rate stability and intergenerational equity.[5]

ALBERTA ENERGY AND UTILITIES BOARD ("AEUB")

In a recent decision dealing with the Alberta Electric System Operator, the AEUB stated:

… the Board has also historically given the concept of rate stability (commonly also referred to as rate shock or rate gradualism) significant weight.[6]

In a 1998 decision, the AEUB dealt with the issue of an interim adjustment to the 1997 rates of Canadian Western Natural Gas Company Limited ("CWNG"). The Board concluded that the utility should make a one-time interim refund of $3.5 million.

In its decision, the AEUB considered the issues of rate shock (i.e., rate stability), financial hardship (i.e., financial integrity) and intergenerational equity. Although the Board concluded that rate shock and financial hardship should not be given much weight, it appears this conclusion reflects the facts of this particular situation:

The Board has considered Calgary's 1997 Adjustment Application and finds that an interim adjustment, by way of a one-time refund to customers in the fashion proposed by CWNG for the 1998 interim rate adjustment, is appropriate. The Board is aware of the various criteria used in previous interim rate decisions, but notes that most of these have been in response to rate increases, not rate refunds. The Board is not persuaded that much weight need be given to the notions of rate shock or financial hardship. The Board considers, however, that intergenerational inequity will be reduced if a timely refund is made.[7]

BRITISH COLUMBIA UTILITIES COMMISSION ("BCUC")

The BCUC has recognized the importance of rate stability and intergenerational equity and the potential trade off between these principles in dealing with other post employment benefits.

---

[5] MPUB; Order No. 163/03 re: Gladstone, Austin Natural Gas Co-Op Ltd.; October 31, 2003; pg. 5-6.

[6] AEUB; Decision 2005-096 re: Alberta Electric System Operator (AESO); August 28, 2005**;** pg. 16.

[7] AEUB; Decision U98162 re: Canadian Western Natural Gas Company Limited; October 26, 1998; pg.2.

In a decision deal with BC Hydro, the BCUC approved a change from the cash to the accrual method. This was at least partially due to the accrual method providing a better matching of costs to the period that service is provided (i.e., intergenerational equity):

> *The Commission Panel finds that the accrual method does provide a better matching of costs to the period in which the service was provided. The Commission Panel further notes that the requested change from the cash basis to the accrual basis of accounting for post retirement benefits will not, in this instance, have a significant affect on rates. Further, the Commission Panel does not consider that the circumstances warrant the costs to BC Hydro and its ratepayers that would be associated with a requirement to fund this obligation.* ***The Commission Panel approves the accounting change from the cash method to the accrual method for post-retirement benefits.*** [8]

In another decision, the BCUC approved the continued use of the accrual method for BC Gas (now Terasen Gas). In doing so it noted that it had previously approved the "pay-as-you-go" method (i.e., cash basis) so as to avoid rate shock:

> *While the Commission has approved the "pay-as-you-go" method for Pacific Northern Gas Ltd. and Aquila Networks Canada (British Columbia) Ltd., it did so to avoid rate shock at the time of the Orders. This situation does not exist for BC Gas.* ***The Commission accepts the continuation of the accrual basis of accounting for OPEB for the 2003 Revenue Requirements.***[9]

NATIONAL ENERGY BOARD ("NEB")

In a 1995 decision, the NEB dealt with the drawdown of Foothills' deferred tax balance. In its decision the NEB recognized the need to maintain the financial integrity of the utility:

> *In this case the Board recognizes that the balance of deferred income taxes represents a large component of the current financing of Foothills' rate base. To finance the drawdown Foothills will need to raise $135.8 million, which equals a 19% increase in its capital structure. A rapid drawdown as proposed by CAPP could affect Foothills' ability to access financial markets on the most reasonable terms.*[10]

The NEB recognized the importance of intergenerational equity. However, the Board concluded that it was not an issue in this case:

---

8 BCUC; re: British Columbia Hydro And Power Authority and British Columbia Transmission Corporation; October 29, 2004; pg. 168.

9 BCUC; BC Gas Utility Ltd.; February 4, 2003; pg. 37.

10 NEB; RH-1-95 re: Foothills Pipe Lines Ltd.; October 1995; pg. 6.

> *The primary arguments presented in support of a fast drawdown were minimization of inter-generational inequity and a higher NPV of the refund in the hands of shippers. The evidence on the issue of inter-generational equity led the Board to conclude that it was unlikely that the period over which the drawdown is made would have any significant impact on the likelihood that those who contributed to the deferred tax pool would share in the drawdown.*[11]

In appears that the NEB considered rate stability to be a major factor in determining the amortization period:

> *The CAPP proposal would result in a wide swing in tolls over a short period. While it is true that the effective roll-in of Zones 6 and 7 tolls with Nova's tolls and Zone 8 tolls with ANG's tolls, masks the effects of these toll swings, the impact would be felt in Zone 9. The Foothills proposal produces the most stable toll projections, however, the Board was not persuaded of the value of a forecast beyond ten years.*
>
> *On balance, the Board finds that the Pan Alberta proposal for a straight line amortization over ten years provides for a smooth transition, while minimizing toll variations.*[12]

---

[11] NEB; RH-1-95 re: Foothills Pipe Lines Ltd.; October 1995; pg. 6.

[12] NEB; RH-1-95 re: Foothills Pipe Lines Ltd.; October 1995; pg. 6.