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September 14, 2012
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British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

**Attention: Ms. Erica M. Hamilton,
Commission Secretary**

Dear Sirs/Mesdames:

**Re: FortisBC Energy Utilities, Project No. 3698652
Common Rates, Amalgamation and Rate Design Application**

In accordance with the Regulatory Timetable set for this proceeding by Order No. G-106-12, the FortisBC Energy Utilities are filing the attached Final Argument and Book of Authorities.

Twelve hard copies of the enclosed will follow by courier.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[Original signed by Christopher Bystrom]

Christopher Bystrom

CRB/ccm
Encl.

BRITISH COLUMBIA UTILITIES COMMISSION

PROJECT NO. 3698652

FORTISBC ENERGY UTILITIES
COMMON RATES, AMALGAMATION AND RATE DESIGN APPLICATION

FINAL ARGUMENT

OF

THE FORTISBC ENERGY UTILITIES

September 14, 2012

FASKEN MARTINEAU DuMOULIN LLP

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1.0 INTRODUCTION

1. FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEW"), together referred to as the "FortisBC Energy Utilities" or the "FEU", are applying for the necessary approvals pursuant to the *Utilities Commission Act* (the "*UCA*") to amalgamate FEI, FEVI and FEW, as well as Terasen Gas Holdings Inc. ("THI"), into a single entity and implement common rates[1] and services across their service areas starting January 1, 2014. The approval of this Application will unite the FEU into a single corporate entity (referred to as "FEI Amalco" or the "Amalgamated Entity") with one rate base and one set of rate schedules and services for all of its approximately 950,000 customers. A draft form of the order sought is included as Appendix K-2 of the Application.[2]

2. Under accepted rate design principles, the FEU submit that common rates are the most fair and equitable approach for all customers of the FEU, reflecting the fact that the FEU are under common ownership, are fully integrated in their management and operations and provide a similar service to all classes of customers. Common rates will result in significantly lower rates for the customers of FEVI and FEW and provide long-term rate stability to the customers of FEVI, FEW and the service area of Fort Nelson (referred to as "Fort Nelson" or "FEFN"). Common rates will also result in other benefits, including rates that are more easily understood and more efficiently administered compared to the FEU's currently diverse and complex set of rate structures.

3. The proposed postage stamp rates for the FEU are also more consistent with the postage stamp rates already applied to the vast majority of natural gas and electric utility ratepayers in this Province. Both BC Hydro and FortisBC Inc. serve their electric customers under postage stamp rates, while the vast majority of natural gas customers (approximately 850,000) are under postage stamp delivery and commodity rates in FEI's Lower Mainland, Inland and Columbia service areas (together referred to as "FEI Mainland"). The regional distinctions that preserve separate rates for the approximately

[1] Common rates are also referred to as postage stamp or harmonized rates.

[2] Exhibit B-3, Application.

102,000 FEVI customers, 2,600 FEW customers and 2,400 FEFN customers are therefore anomalous. Moreover, the source of these anomalous regional distinctions is corporate history rather than any considered rate design approach. Given that the key aspects of the Special Direction governing FEVI's rates has come to an end and FEW has converted to natural gas, it is now both logical and appropriate to extend to the customers of FEVI, FEW and FEFN the postage stamp rate approach that is otherwise applied evenly in the Province and in accordance with government policy.

4. Based on the information requests in this proceeding, four principal issues with the proposal to implement postage stamp rates and amalgamate the FEU are: the mitigation of the rate impacts to FEI Mainland customers, the appropriate risk premium, FEI's rate design and the inclusion of Fort Nelson. As discussed briefly below, none of these issues should prevent the Commission from approving the substance of the requests being sought in the FEU's Application.

5. First, an issue in this proceeding is how to mitigate the rate impact to FEI Mainland customers. As discussed in section 4.5 below, the FEU have proposed a three-year phase-in approach through the distribution of the balance in FEVI's Rate Stabilization Deferral Account ("RSDA"). Various other phase-in approaches have been described in responses to information requests, including options that would phase-in the rate decreases to FEVI and FEW. While there may be disagreement over the appropriate approach, each phase-in option ultimately results in the implementation of postage stamp rates.

6. Second, with respect to the risk premium, the FEU have proposed that FEI Amalco has a 12 basis point premium over the current benchmark return on equity ("ROE"), representing the weighted average of the current ROE of the FEU. As recommended by Ms. McShane, an expert in cost of capital, this appropriately represents the upper end of the acceptable range for FEI Amalco.[3] The FEU acknowledge, however, that there is an acceptable range for the cost of capital and that the cost of capital is only being set on an interim basis due to the General Cost of Capital ("GCOC") proceeding. The precise risk

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[3] Exhibit B-3-1, Appendix C-4, "Opinion on Impact of Amalgamation on Cost of Capital".

premium within the acceptable range should not be a barrier to the overall approval of amalgamation and postage stamp rates.

7. Third, the harmonization of rates is proposed to be accomplished by extending FEI's existing rate structures to FEVI, FEW and Fort Nelson. This is a reasonable and appropriate approach as the FEI structure has been established for the vast majority of natural gas customers, and is simply being extended to the remaining FEU customers. However, generic or broader rate design issues have been raised during the proceeding that are not relevant to the proposed extension of FEI's rate structures *per se*. Whether or not amalgamation is approved, the FEU will be revisiting the rate design of the FEU or FEI Amalco which will provide an opportunity for rate design issues to be considered in the ordinary course. If amalgamation is approved, FEI Amalco will be preparing to file a rate design in the later part of 2016.[4] This time frame should provide time for customers of FEVI, FEW and FEFN to settle into the new rate schedules available to them and provide FEI Amalco with time to conduct the appropriate studies and prepare its rate design proposals and application.

8. Fourth, the FEU's proposal to include Fort Nelson in postage stamp rates would result in a significant rate impact to Fort Nelson customers. While the FEU submit that the extension of postage rates to Fort Nelson is appropriate with the 15-year phase-in proposed, the exclusion of the approximately 2,400 customers of Fort Nelson from postage stamp rates is not a barrier to proceeding with amalgamation and postage stamp rates for all other service areas. If the Commission were to exclude Fort Nelson at this time, Fort Nelson could continue as a separate rate base of FEI and this would have no material impact on any of the other approximately 950,000 FEU customers.

9. In summary, the FEU submit that regardless of how these four principal issues are determined, they should not lead to the rejection of the core approvals being sought by the FEU. Regardless of which phase-in option is adopted, which risk premium approved, or whether Fort Nelson is included, the FEU submit that its proposal to implement

[4] Exhibit B-3, p. 221; Exhibit B-15, BCUC IR 2.58.1.

postage stamp rates through amalgamation is just and reasonable and in the public interest.

10. The remainder of this submission is organized under the following main subject headings:

(a) Approvals Sought

(b) Postage Stamp Rates are Supported by Policy and Regulatory Authority

(c) Postage Stamp Rates are Supported by Rate Design Principles

(d) Additional Benefits of Amalgamation and Postage Stamp Rates

(e) Service Area-Specific Issues

(f) Alternative Amalgamation Scenarios

(g) Implementation and Operation

(h) Cost of Service Issues

(i) Interim Cost of Capital

(j) Rate Design

(k) Consultation

(l) Conclusion

2.0 APPROVALS SOUGHT

11. In this Application, the FEU are seeking the Commission's approval to implement postage stamp rates as of January 1, 2014 and, in order to accomplish this, to amalgamate the FEI, FEVI, and FEW, along with THI.[5] Although these approvals are sought under different sections of the *UCA*, these approvals are intimately related and must be considered together as discussed below. In the following subsections, the FEU discuss the approvals sought.

2.1 Approvals to Implement Common Rates

12. Pursuant to sections 59 to 61 of the *UCA*, the FEU are seeking the approval of the Commission that the proposed postage stamp delivery, midstream and commodity rates for the Amalgamated Entity are just and reasonable. In particular, in order to implement postage stamp rates, the FEU are seeking the following orders effective January 1, 2014, subject to the approval of the amalgamation:

(a) Approval of the discontinuance of the energy, delivery, and commodity rates of FEVI, FEW and FEI's service area of Fort Nelson.

(b) Approval of the amended FEI rate schedules for the Amalgamated Entity as set out in Exhibit B-3-1, Appendix B-2 as updated in Attachment 118.1 of Exhibit B-9-1.[6]

(c) Approval of the FEI Amalco delivery rates on an interim basis as set out in Appendix J-3.

(d) Approval of the use of a combined gas portfolio for FEI Amalco.

(e) Approval of the discontinuance of FEVI's, FEW's and Fort Nelson's existing terms and conditions of service and approval of the amendments to FEI's General Terms and Conditions ("GT&Cs") to be applicable to the Amalgamated Entity, as set out in Attachment 73.1 to Exhibit B-15, with deferral of extension of the

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[5] For the explanation of the request for amalgamation with THI, see Exhibit B-3, Application, p. 9.

[6] See Exhibit B-15, BCUC IR 2.74.1 for a summary of corrections made.

Customer Choice Program pending a further application by the Amalgamated Entity.

(f) Approval of the service agreement with the Vancouver Island Gas Joint Venture set out in Attachment 78.3 of Exhibit B-15.

(g) Approval of the use of the FEI and FEVI main extension test (the "MX Test") for FEI Amalco.

(h) Approval of the RSDA Rate Rider, to permit the distribution of the balance in the RSDA to FEI's non-bypass customers to mitigate rate impacts of postage stamp rates.

(i) Approval of continuation or merger of approved deferral accounts for the FEU and approval of four new deferral accounts: the Amalgamation Costs Deferral Account; the Company Use and Unaccounted For Gas Cost Variance Account; the Amalgamation and Rate Design Application Costs; and the Fort Nelson Phase-In Rate Rider Account.

(j) Approval of the discontinuance of the Corporate Services Agreement between FortisBC Holdings Inc. and each of FEVI and FEW, leaving the agreement with FEI to remain in place for the Amalgamated Entity as amended to include FEVI and FEW costs as set out in Appendix F of the Application.

(k) Approval of the adoption of FEI's Transfer Pricing Policy and Code of Conduct, as approved by the Commission in Letter L-64-1997, as the Transfer Pricing Policy and Code of Conduct of the Amalgamated Entity.

(l) Approval of the adjustment of the conditions specified in Commission Order No. G-49-07 relating to the acquisition of Terasen Inc. (now FortisBC Holdings Inc.) by Fortis Inc. as necessary to reflect the amalgamation of the FEU.

13. Based on the evidence in this proceeding, the FEU submit that the rates sought are just and reasonable and in the public interest.

14. As explained on pages 14 and 15 of the Application, the FEU are seeking interim rates only at this time. Permanent delivery rates would be set through the 2014 revenue requirements proceeding and based on the outcome of the General Cost of Capital proceeding and any subsequent proceeding to set any risk premium above benchmark for FEI Amalco. The FEU would seek approval of the commodity and midstream rates for FEI Amalco through the 2013 fourth quarter gas filing, as is currently done for FEI.

2.2 Approvals to Amalgamate

15. In order to be able to implement the proposed postage stamp rates, the FEU are applying to the Commission in accordance with section 53(3) of the *UCA* for the consent of the Lieutenant Governor in Council (the "LGIC") to amalgamate the FEU and THI. Subsections 53(1) to (5) of the *UCA* state:

> 53 (1) A public utility must not consolidate, amalgamate or merge with another person
>
> (a) unless the Lieutenant Governor in Council
>
> (i) has first received from the commission a report under this section including an opinion that the consolidation, amalgamation or merger would be beneficial in the public interest, and
>
> (ii) has, by order, consented to the consolidation, amalgamation or merger, and
>
> (b) except in accordance with an order made under paragraph (a).
>
> (2) The Lieutenant Governor in Council may, in an order under subsection (1) (a), include conditions and requirements that the Lieutenant Governor in Council considers necessary or advisable.
>
> (3) An application for consent of the Lieutenant Governor in Council under subsection (1) must be made to the commission by the public utility.
>
> (4) The commission must inquire into the application and may for that purpose hold a hearing.
>
> (5) On conclusion of its inquiry, the commission must,

(a) if it is of the opinion that the consolidation, amalgamation or merger would be beneficial in the public interest, submit its report and findings to the Lieutenant Governor in Council, or

(b) dismiss the application.

16. In accordance with the above and based on the evidence in this proceeding, the FEU are requesting that the Commission find that the amalgamation of the FEU and THI is beneficial in the public interest and that the Commission submit a report of its findings to the LGIC as set out in section 53(4) of the *UCA*. Ultimate approval of the amalgamation is dependent upon the consent of the LGIC as contemplated in section 53(1) of the *UCA*.

2.2.1 Criteria for Assessing Amalgamation

17. Past Commission decisions have identified criteria for assessing a merger, acquisition, amalgamation or consolidation. The Commission's August 5, 1992 BC Gas Inc. Revenue Requirement Application Reasons for Decision (the "1992 BC Gas Decision") indicated that in considering requests for the approval of a merger, acquisition, amalgamation or consolidation, the Commission has historically applied a set of criteria.[7] The criteria listed in the 1992 BC Gas Decision are similar to the six evaluation criteria referenced by the Commission's November 10, 2005 Decision on the Kinder Morgan Inc. acquisition of Terasen Inc. (the "KMI Decision").[8] These 6 criteria are:

- the utility's current and future ability to raise equity and debt financing not be reduced or impaired;
- there be no violation of existing covenants that will be detrimental to the customers;
- the conduct of the utility's business, including the level of service, either now or in the future, will be maintained or enhanced;
- the application is in compliance with appropriate enactments and/or regulations;
- the structural integrity of the assets will be maintained in such a manner as to not impair utility service; and
- the public interest will be preserved.

[7] Exhibit A2-1, pp. 16 and 17: the criteria are (i) the utility's ability to finance future capital requirements; (ii) the continuation of existing covenants that would preserve the customer's interest; (iii) the utility's ability to maintain the required level of service into the future; (iv), the preservation of the public interest; and (v), compliance with pertinent legislation and regulations.

[8] Exhibit B-9, preamble to BCUC IR 1.5.1. The KMI Decision is also online at: http://www.bcuc.com/Documents/Proceedings/2005/DOC_9223_KMI-Terasen%20Decision_FINAL2.pdf

18. While the criteria from the 1992 BC Gas Decision and KMI Decision are relevant considerations, they are focussed on whether there would be any detrimental impact from the transaction, and thus appear to be more relevant to an acquisition under section 54 of the *UCA*, rather than the amalgamation of companies already under common ownership and management pursuant to section 53 of the *UCA*.[9] The table below discusses each of the criteria.

Criteria	Summary of Evidence
The utility's current and future ability to raise equity and debt financing not be reduced or impaired	Assuming any approval does not have a material impact on the amalgamated entity's allowed ROE or capital structure, or credit ratings, the FEU anticipate that amalgamation would not reduce or impair the amalgamated entity's ability to raise financing.[10]
No violation of existing covenants that will be detrimental to the customers	There will be no violation of existing covenants.[11]
The conduct of the utility's business, including the level of service, either now or in the future, will be maintained or enhanced	The approval of legal amalgamation would not negatively affect the conduct of the utility's business, including the level of service, either now or in the future. The effect of legal amalgamation is one of simplification of the corporate structure of the FEU as opposed to an operational amalgamation. Therefore, the day-to-day operations of the business will not be affected by the legal amalgamation.[12]
The application is in compliance with appropriate enactments and/or regulations	Approval of legal amalgamation would not result in non-compliance with appropriate enactments and/or regulations. The FEU are seeking approval to amalgamate in accordance with section 53 of the *UCA*. If approval is granted, the FEU will implement amalgamation in accordance with the provisions of the *Business Corporations Act* and will comply with all appropriate enactments and regulations.[13]
The structural integrity of the assets will be maintained in such a manner as to not impair utility service	The approval of legal amalgamation will not result in a reduction in the structural integrity of the assets in such a manner as to impair

[9] Exhibit B-9, BCUC IR 1.5.1.
[10] Exhibit B-9, BCUC IR 1.5.5.
[11] Exhibit B-9, BCUC IR 1.5.6.
[12] Exhibit B-9, BCUC IR 1.5.7.
[13] Exhibit B-9, BCUC IR 1.5.8.

	utility service. The FEU's assets are maintained in a consistent manner across the service areas, and legal amalgamation will not negatively impact asset integrity activities or reduce the structural integrity of the assets. Asset integrity activity is primarily code and compliance driven by regulatory bodies that are independent of a legal amalgamation of the FEU.[14]
The public interest will be preserved	In the FEU's submission, the public interest is preserved under its proposed amalgamation. The public interest considerations are discussed below in sections 3, 4, and 5 of this submission.

19. The FEU submit that the criteria from the 1992 BC Gas Decision and KMI Decision are satisfied, with the key issue being the public interest criteria, which will be the focus of this submission.

2.3 Evaluation Framework for Approvals Sought

20. The FEU's proposals to implement postage stamp rates and to amalgamate the FEU are interdependent and cannot be separated. While postage stamp rates can only be implemented with amalgamation, the primary benefit of amalgamation is that it facilitates implementation of postage stamp rates.[15] As such, the FEU submit that its proposal to amalgamate and implement postage stamp rates must be considered together.

21. Similar to all rate design proposals, in evaluating the proposed postage stamp rates and amalgamation, the Commission should consider the relevant provisions of the *UCA*, the application of accepted rate design principles, and any other relevant factors based on the evidence in the proceeding. As is usually the case with Commission determinations, the factors to be considered and weighed are complex and multi-faceted and do not lend themselves to resolution through the application of a formula. For example, the Commission must weigh together positive and negative bill impacts, overall financial savings, consistency with government policy, and the benefits of rate stability and ease of administration and simplicity. Such factors as these are not quantifiable on a comparable

[14] Exhibit B-9, BCUC IR 1.5.9.
[15] Exhibit B-9, BCUC IR 1.2.1 and 1.5.3 and Exhibit B-15, BCUC IR 2.2.1

basis. Nonetheless, the Commission must weigh all the factors based on the evidence before it and come to an opinion regarding what is in the public interest.[16]

22. Of particular relevance is the fact that the FEU's rate design work for this Application has been supported by an external expert in cost allocation and rate design, Mr. Gary Saleba of EES Consulting Ltd. ("EES Consulting").[17] Mr. Saleba's qualifications are found as Attachment 1 to the Natural Gas Cost of Service Review prepared by EES Consulting included as Appendix D-1 of the Application.[18] Mr. Saleba has 40 years of experience as an economist and rate design expert and has been the President of EES Consulting for over 30 years. Over the course of his career, Mr. Saleba has provided expert testimony in numerous proceeding in the United States and Canada, including in previous Commission proceedings.[19] The proposed postage stamp rate design has been endorsed by Mr. Saleba and is consistent with accepted rate design principles. No other expert evidence has been tendered in this proceeding which challenges Mr. Saleba's conclusions.

23. In the following sections of this submission, the FEU analyze the amalgamation and postage stamp rate proposal from the perspective of regulatory authority, government policy, rate design principles and the other benefits they bring to customers. The FEU submit that when the whole of the evidence is considered, the Commission should conclude that the FEU's proposed postage stamp rates are just and reasonable and the proposed amalgamation is beneficial in the public interest.

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[16] Exhibit B-15, BCUC IR 2.40.3.
[17] Exhibit B-3, Application, p. 6.
[18] Exhibit B-3-1.
[19] Exhibit B-3-1, Appendix D-1, Attachment 1.

3.0 POSTAGE STAMP RATES ARE SUPPORTED BY POLICY AND REGULATORY AUTHORITY

24. The FEU submit that postage stamp rates are the predominant rate design for public utilities in the Province and are supported by government policy. The FEU also submit that postage stamp rates are supported by the weight of Canadian regulatory authority. The support from a policy and regulatory authority perspective is discussed below.

3.1 Postage Stamp Rates Reflect Established Policy

25. As discussed in this section, postage stamp rates are the most common rate design employed in British Columbia, the most common form of rate design for natural gas distribution utilities in Canada and the U.S. and are supported by provincial government policy.

26. Postage stamp rates are employed by the vast majority of utilities in British Columbia, including BC Hydro, FortisBC Inc., FEI, FEVI and FEW. BC Hydro first implemented postage stamp rates in October 1962, shortly after its formation in March 1962.[20] FEI has postage stamp delivery and commodity rates for all customers except for those in Fort Nelson, while retaining minor variations in its midstream rate.

27. Municipalities that operate utilities also utilize postage stamp rates. The Association of Vancouver Island and Coastal Communities states:[21]

> AVICC believes that postage stamp rates are the most appropriate rate structure for public utility services. AVICC members are themselves operators of many public utility services, the rates for most of which, like property tax rates within classes, are set uniformly across a jurisdiction so this is the model they are most familiar with.

28. Postage stamp rates are also the most common form of rate design employed by natural gas distribution utilities in Canada generally. Canadian natural gas utilities employing postage stamp rates include, for instance, AltaGas, Centra Gas Manitoba, Heritage Gas,

[20] Exhibit B-15, BCUC IR 2.9.1.

[21] Exhibit C9-3, p. 4, AVICC response to BCUC IR 1.1.1.

Gaz Metro, and SaskEnergy,[22] as well as Enbridge Gas Inc.[23] Based on EES Consulting's wide experience,[24] the majority of gas and electric utilities in the U.S. also use postage stamp rates.[25] In short, postage stamp rates are the predominant rate design.

29. There is ample evidence that government policy is in support of postage stamp rates.[26] This evidence includes:

(a) In the BC Hydro 2007 Rate Design Application (RDA), BC Hydro filed a 2003 letter from the Minister of Energy to the President of the Union of BC Municipalities that made direct commitment to the continuance of the postage stamp rate design in the context of the Heritage Contract Inquiry (BC Hydro 2007 RDA, Exhibit B-47, included as Attachment 13.1).[27]

(b) BC Hydro, a Crown corporation, has stated that postage stamp rates are a "fundamental rate design objective" and "a cornerstone of rate design for BC Hydro."[28]

(c) In the case of the amalgamation of Terasen Gas (Squamish) Inc. into FEI the provincial government supported the postage stamp rate principle in place for FEI by requiring in Special Direction No. 3 (dated Nov. 2, 2006) that "(i)n regulating and fixing rates for amalgamated TGI, the commission must apply the Terasen Gas Inc. Tariff and must not apply the Terasen Gas (Squamish) Inc. Gas Tariff."[29]

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[22] Exhibit B-15, BCUC IR 2.9.2.

[23] Ontario Energy Board, EB-2011-0277, Interim Rate Order, dated December 9, 2011, Appendix B. (available online at: https://www.enbridgegas.com/DocumentBrowser/Rate%20Cases%20and%20QRAMs/2012%20Rate%20Adjustment/EB-2011-0277/3%20-%20Decision/20111209%20OEB%20rate_order_Interim_EGDI_2012%20IRM.pdf). Enbridge Gas Inc.'s 2012 interim rates were made final by Ontario Energy Board, EB-2011-0277, Decision and Order dated May 10, 2011 (available online at: https://www.enbridgegas.com/DocumentBrowser/Rate%20Cases%20and%20QRAMs/2012%20Rate%20Adjustment/EB-2011-0277/3%20-%20Decision/20120510%20OEB%20Decision%20and%20Order.pdf).

[24] Exhibit B-3-1, Appendix D-1.

[25] Exhibit B-15, BCUC IR 2.9.2.

[26] Exhibit B-9, BCUC IR 1.13.1; Exhibit B-15, BCUC IR 2.7.1 and 2.7.2.

[27] Exhibit B-9, BCUC IR 1.13.1.

[28] Exhibit B-9, BCUC IR 1.13.1.

[29] Exhibit B-9, BCUC IR 1.13.1. See Exhibit B-9, response to BCUC IR 1.18.1, 1.18.2 and 1.18.3 and Exhibit B-12, BCRUCA 2.4.1 for further background information on the amalgamation with Squamish Gas Co. Ltd.

(d) Based on the FEU's discussions with the Ministry, the FEU believe that the provincial government's policy is, and continues to be, in favour of postage stamp rates. The FEU understand that the Ministry did not intervene in this case in support of postage stamp rates because the policy of postage stamp rates is well established.[30]

(e) The provincial government's planned review of industrial electricity policy has been necessitated by the potential for large new industrial loads such as from the electrification of the oil and gas sector in the northeast of the province or the development of LNG export facilities on the northwest coast of the province. This review is limited to *industrial* electricity policy and does not mark a change in the government's views about postage stamp rates generally, particularly with respect to postage stamp rates as they apply to the residential, commercial and general service classes that make up over 99% of BC Hydro's customer base.[31]

30. In the FortisBC Inc. 2009 Rate Design and Cost of Service Analysis Decision, dated October 19, 2010, the Commission concluded that the postage stamp principle followed by FortisBC Inc. is supported by government policy.[32] In the FEU's submission, the evidence supports the same conclusion in this case.

31. The FEU therefore submit that its proposal to adopt postage stamp rates for FEI Amalco reflects the most established and commonly used rate design policy.

3.2 Postage Stamp Rates are Supported by the Weight of Canadian Regulatory Authority

32. The FEU submit that the weight of regulatory authority is in support of postage stamp rates. The relevant Commission and Canadian precedents are discussed below.

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[30] Exhibit B-15, BCUC IR 2.7.1 and 2.7.2.

[31] Exhibit B-15, BCUC IR 2.7.2.

[32] Exhibit B-9, BCUC IR 1.13.1.

3.2.1 Commission Precedents

33. Past Commission Decisions have approved and upheld the postage stamp rate principle. These decisions are reviewed below.

3.2.1.1 BC Gas 1993 Phase B Rate Design Decision

34. In its 1993 Phase B Rate Design Application, B.C. Gas Utilities Ltd. ("BCGUL") requested postage stamp rates for its residential, commercial and general firm service customers across the Lower Mainland, Inland and Columbia Divisions. In Order G-101-93, the Commission approved postage stamp delivery charges for the Inland and Lower Mainland residential, commercial, seasonal, general firm service and NGV customers.[33] At that time, however, the Commission concluded that the Columbia Division was sufficiently different from the Inland and Lower Mainland Divisions, and therefore did not approve postage stamping of the Columbia Division in principle. Nonetheless, BCGUL was allowed to set the delivery charges for the Columbia Service Area at the same rates as those in the Lower Mainland and Inland Service Areas. The delivery charges for residential, commercial and general firm service in the Columbia service area have remained the same as those in the Lower Mainland and Inland Service Areas since January 1, 1994, for more than 18 years. In subsequent proceedings, the gas supply portfolio of the Columbia service area was merged with the Lower Mainland and Inland service areas and commodity rates were postage stamped across the service areas.[34]

35. The FEU submit that the *de facto* effect of the Phase B Rate Design decision was to postage stamp delivery rates for the Lower Mainland, Columbia and Inland service areas of FEI and that since that decision FEI's rates have converged in conformity with the postage stamp rate principle.

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[33] Exhibit A2-2, BCUC Order G-101-93, BC Gas Utility Ltd. 1993 Phase B Rate Design Application Decision, dated October 25, 1993, at p. 10.

[34] Exhibit B-9, BCUC IR 1.17.6.

3.2.1.2 Chetwynd Complaint: BCUC Letter No. L-24-04

36. In Letter No. L-24-04 the Commission upheld FEI's postage stamp rates, rejecting a complaint from the District of Chetwynd that FEI's rates were unjust and unreasonable.[35] The Commission stated:

> Allocating the total cost of service among the different ratepayers so as to avoid arbitrariness and cross-subsidization is important, but not the only factor to be considered when determining the reasonableness of rates. Other important factors include administrative simplicity, understandability and stability of rates.
>
> …
>
> The Commission is not persuaded that the cost of service analysis provides sufficient justification to require Terasen Gas to amend the rates to the District of Chetwynd. As noted above, there are other important considerations to consider when setting rates such as administrative simplicity, stability and understandability. To set a rate for a single municipality or district raises serious issues about how far the boundaries of the rates should extend, and how the utility would adjust rates for other customers if the rates to one district were changed. The appropriate forum for considering the rates charged to various customer classes (whether those classes are defined by geographic area or by customer characteristics) is within a rate design hearing so that other affected customers may respond, as well as the utility. Therefore, the Commission dismisses Chetwynd's complaint.

37. As indicated above, this decision recognized the importance of the rate design principles of administrative simplicity, understandability and stability of rates. It also recognized the difficulty of where to draw the line if it were to be determined that one district should have separate rate treatment.

3.2.1.3 Big White Rate Design: BCUC Order G-87-07

38. In September 2007 Commission Order No. C-17-06 granted FortisBC Inc. a CPCN for the Big White Supply Project to construct a transmission line to a new substation at Big White Village. Order No. C-17-06 also ordered FortisBC Inc. to file a rate design application regarding whether the costs of the project were to be recovered from Big

[35] BCUC Letter No. L-24-04, dated April 23, 2004, at Tab 1 of the FEU's Book of Authorities.

White customers alone or rolled into FortisBC Inc.'s postage stamp rates. BCUC Order G-87-07 upheld the postage stamp principle, stating:[36]

> In the view of the Commission Panel, the COS information and much of the other information to be discussed below, is new information relative to the information available during the CPCN proceeding and to the CPCN Panel and this information supports rolling the costs of the Project into the FortisBC rate base. The COS analysis demonstrates that with the Project costs rolled into the FortisBC rate base, the Big White area will be covering between 116 percent to 123 percent of the costs associated with the area. Even with the Project costs assigned directly to the Big White area, the revenue to cost ratio is approximately 84 percent after load growth has occurred. The Commission Panel agrees with FortisBC that all of these results fall within the range of revenue to cost ratios of the other communities in the FortisBC area that were analyzed and notes that the EES Report (p. 13) suggests that the entire FortisBC service area would face a similar variability between areas and towns.
>
> Moreover, rolling the Project costs into rate base would be consistent with the Commission approval of the British Columbia Transmission Corporation Whistler reinforcement project without any requirement for any rate revisions or contributions from Whistler ratepayers.
>
> The Commission Panel, therefore, agrees with FortisBC that an analysis of the revenues and allocated costs indicates that Big White is not sufficiently different from other areas in FortisBC's service territory to warrant special and unique retail rate treatment. The Commission notes that comparable transmission upgrades for other communities have been undertaken and have not attracted special rates or funding requirements, including the Whistler project and the FortisBC Nk'Mip project in the Osoyoos area.

39. As indicated above, in upholding postage stamp rates, this Decision recognized the cost of service variability within FortisBC Inc.'s service territory and the fact that the cost of capital projects have been historically rolled into postage stamp rates, in particular projects to serve other resort communities such as Whistler.

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[36] BCUC Order G-87-07, dated August 7, 2007, Appendix A, p. 15 of 18, at Tab 2 of the FEU's Book of Authorities.

3.2.1.4 FortisBC Inc. 2009 Rate Design Application

40. The issue of postage stamp rates was raised in FortisBC Inc.'s 2009 Rate Design and Cost of Service Analysis proceeding.[37] As described in the Commission's Decision dated October 19, 2010, an intervenor questioned the equities between West Kootenay customers and North Okanagan customers. FortisBC Inc. indicated that it had investigated but rejected alternatives to postage stamp rates and argued that postage stamp rates reduced price fluctuations to regional subgroups and also reflected differences in the reliability of service.[38] The Commission upheld the postage stamp rates structure, indicating that it had insufficient information to justify a departure and noting the government policy in favour of postage stamp rates.[39]

3.2.1.5 Conclusion on Commission Decisions

41. While the Commission's decisions discussed above related to postage stamp rates are not determinative in this case, the FEU submit that the weight of Commission authority is in support of the application of postage stamp rates. The Commission has accepted the application of postage stamp rates over FEI's broad service areas, and has not been persuaded that distinct rate treatment is required for the relatively remote municipality of Chetwynd. The Commission has also not been persuaded that a separate rate treatment is required for resort communities such as Big White in FortisBC Inc.'s service territory and has acknowledged the government policy in favour of postage stamp rates for FortisBC Inc.

3.2.2 Other Canadian Jurisdictions

42. The FEU have also reviewed other Canadian regulatory authority relating to postage stamp rates. The following subsections review Canadian regulatory decisions that the FEU are aware of related to postage stamp rates. The FEU submit that the weight of these regulatory authorities is also supportive of postage stamp rates.

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[37] Commission Decision, FortisBC Inc. 2009 Rate Design and Cost of Service Analysis dated October 19, 2010, pp. 67-69 (at Tab 3 of the FEU's Book of Authorities).

[38] Ibid., pp. 67-68.

[39] Ibid, at 69.

3.2.2.1 Newfoundland & Labrador Hydro 2003 General Rate Application

43. In its 2003 General Rate Application to the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board"), Newfoundland and Labrador Hydro ("NLH") proposed to implement uniform rates for customers in Labrador East and Labrador West as previously approved by the Board.[40] NLH proposed a five year phase-in period. The Board Decision describes the rate impact as follows:[41]

> The proposed phase-in of uniform rates outlined above limits average rate increases for each class to a maximum of 20% in years 2005 to 2008. However, the revenue requirement necessitates a 28% increase in 2004 for Labrador West.

44. The Towns of Wabush and Labrador City in Labrador West filed a complaint arguing that the uniform rates were discriminatory. The two communities argued that Labrador East and Labrador West should be considered separately for rate setting purposes because of the significant cost differences between the two systems and also because of the historical factors contributing to the development of the Labrador West system.

45. The Board rejected the argument that the historical development of the electrical system should be a relevant factor in determining whether or not to implement uniform rates, holding that "the Board is only concerned with setting rates on a prospective basis as required by legislation."[42] The Board also rejected the argument regarding cost difference, stating:[43]

> The Board accepts that there are cost differences between Labrador West and Labrador East. While not confirming the costs as presented by Mr. Drazen, NLH also acknowledged that there are cost differences. The costs in Labrador East are calculated by Mr. Drazen to be in the range of 1.7-2.5 times higher, depending on which COS treatment is assumed for the standby generation in Happy Valley-Goose Bay. (Revised Evidence, M. Drazen, Oct. 3, 2003, pg. 1)

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[40] Newfoundland and Labrador Board of Commissioners of Public Utilities, Order No. P.U. 14 (2004), at pp. l01 to 114, at Tab 4 of the FEU's Book of Authorities.

[41] Ibid., at p. 105.

[42] Ibid, at p. 111.

[43] Ibid., at p. 112-113.

The Board agrees with the opinion of Mr. Greneman however that the fact that there are cost differences does not in and of itself justify separation of the system for rate setting purposes. A sub-dividing of any other geographic area or region on the Island Interconnected System for example would in all likelihood result in cost differences between the two. However the Board would have to be satisfied that there is a valid reason to identify and segregate the different costs for the provision of service before proceeding to develop separate rates for the different areas.

…

The Board interprets Section 73(1) of the Act to mean that all customers of a particular utility under substantially similar circumstances and conditions in respect of service of the same description must be charged the same rate. The Board concludes that Labrador West and Labrador East must be considered to be receiving a service of the same description in that they are served by the same generation. The Board further finds that Labrador West and Labrador East must be considered to be receiving this service under substantially similar circumstances and conditions since they are connected to each other and thereby can together be distinguished from the Isolated Systems in the rest of Labrador. The Board accepts the evidence of EES Consulting that it is standard practice for distribution utilities to charge a single rate for the full interconnected system. This approach has been taken by the Board in the past when communities were added to the Island Interconnected System and customers in these communities were charged the same rate as other customers on the Interconnected System. (IC-65)

The COS studies undertaken by NLH for the purposes of setting rates for its Isolated Rural customers embody the principle that substantially similar circumstances do not mean identical circumstances. Although electrically isolated from each other NLH's 24 isolated diesel systems in the Province, both on the Labrador Coast and on the Island, are grouped together for the purposes of COS and setting rates. This approach recognizes that, while not interconnected and in fact widely dispersed geographically, customers in these systems are charged the same rates for the same service under substantially similar circumstances and conditions in respect of service. A consistent approach would lead to the same conclusion for customers in Labrador West and Labrador East.

The Board finds that the Towns of Labrador City and Wabush have not established that the rates for the Labrador Interconnected

> system proposed by NLH are discriminatory. The Board does not accept that the historical development of the costs of the Labrador Interconnected System should be determinative. The Board is required to observe Section 73(1) of the Act. While it may be argued that the historical development or the costs of a system are factors to be considered in the determination of substantially similar circumstances and conditions, the Board notes that the same could be said in respect of a determination for any of the customers of NLH.
>
> Each customer or group of customers of NLH could argue that they cause less costs than another customer or group of customers or that the history of the system providing the service is different. The basic goal of cost of service is to determine the relative cost differences between customer classes. The Board is satisfied that the customers on the Labrador Interconnected System are provided service of the same description under substantially similar circumstances and conditions. The Board concludes a single COS study for customers on the Labrador Interconnected System is appropriate as the basis for determining the rates for all customers on that system. NLH's proposals for uniform rates on the Labrador Interconnected System were developed using a single COS study and are therefore appropriately determined.

46. Accordingly, the Board found that the uniform rate was not unjustly discriminatory and rejected the Labrador West complaint.

47. As indicated in the reasoning above, the Board in this case was persuaded by many of the same regulatory principles and logic applied by the FEU in its current Application. As will be discussed below, although there are differences in costs amongst FEI, FEVI, FEW and FEFN, the FEU submit that all customers of the FEU are receiving substantially similar service via an operationally or physically interconnected system, that variances in cost of service exist across the postage stamped service areas already, and that it is therefore more fair to allocate costs to customer classes regardless of location.

3.2.2.2 Nova Gas Transmission Ltd.

48. The Alberta Energy and Utilities Board (the "EUB") has considered postage stamp rates in relation to Nova Gas Transmission Ltd. ("NGTL") on two occasions.[44] NGTL is an inter-provincial transmission pipeline company, providing intra and inter-Alberta

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[44] Excerpts included in Exhibits A2-4 and A2-5.

transportation services to a variety of market participants.[45] In NGTL's 1995, General Rate Application- Phase II, shippers argued for a change in NGTL's transmission line toll from a postage stamp to a locational rate. The EUB expressed a number of concerns with this proposal, including that the change to locational rates would result in secondary effects, such as changing flow patterns on the system and potentially leading to inefficiencies, or stranded costs on a regional and localized basis. The EUB concluded:[46]

> For the foregoing reasons, the Board is not persuaded that a fundamental shift in NGTL's rate design as embodied in PanCanadian's proposal for locational tolls would be justified at this time. The Board is of the view that the evidence in this proceeding favours the continuation of postage stamp rates on NGTL. They continue to satisfy generally acceptable rate design criteria and to appropriately balance various objectives, goals and interests. Therefore, the Board finds that postage stamp rates continue to be in the public interest.

49. The EUB considered the issue again in 2000 in NGTL's 1999 Products and Pricing Application. The EUB noted that circumstances had changed since NGTL's 1995 GTA:[47]

> The Board believes that the present examination of the appropriateness of NGTL's existing postage stamp rate design reflects a growing concern about natural gas transportation costs in a very competitive market. In the few years since the GRA, the evidence is clear that NGTL has faced significant challenges. Competition in natural gas transportation has intensified and competing alternate pipelines have forced NGTL to mitigate the potential erosion of its customer base by providing alternatives to postage stamp tolling. Such bypass threats and the introduction of load retention services and other discounting approaches exercised by NGTL to address them have, however, increased the risk of future higher rates for remaining customers. This, in turn, could lead to further competitive pressures. Therefore both the pipeline and its customers are interested in ensuring that the toll design does not exacerbate this situation.

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[45] EUB Decision 2000-6 (February 2000), pp. 3-7 (Tab 5 of the FEU's Book of Authorities).

[46] Exhibit A2-4, p. 27.

[47] EUB Decision 2000-6 (February 2000), p. 45 (Tab 5 of the FEU's Book of Authorities).

50. The EUB considered various proposals by NGTL and the parties to the proceeding and evaluated them based on rate design principles and various goals and objectives put forward. The Board adopted the proposal put forward by NGTL, which incorporated a receipt point-specific toll, but retained many of the simplifying assumptions of its postage stamp rate design and did not change the intra-Alberta delivery charge of $0 or the single rate for the ex-Alberta delivery charge.[48]

51. In the case of NGTL, it is apparent that postage stamp rates were threatening to lead some shippers to bypass the system and increase rates for all customers due to the competition for natural gas transportation at the time. In contrast, as discussed below, the FEU's proposed postage stamp rates will lead to efficiencies and increased competitiveness for FEVI and FEW customers, while having no material impact on competitiveness for FEI.

3.2.2.3 AltaGas Utilities Inc., Bonnyville Service Area

52. In 2003, AltaGas Utilities Inc. ("AltaGas") applied to the EUB to harmonize the rates of its Bonnyville service area with the rest of the AltaGas service area. As explained in EUB Decision 2003-052, the Bonnyville Gas Company Limited amalgamated with AltaGas in 2001. The EUB denied the application as it would have caused rates to decrease and then increase and also because the request was premature due to an ongoing rate case.[49]

53. Later in 2003, AltaGas applied again to harmonize Bonneville's rates and on this occasion the application was approved. The EUB noted that the application was unopposed and that its concerns with the previous application had been addressed. The EUB concluded "that as no customers have contested the realignment of Bonnyville Service Area's rates, and that the harmonization of rates will provide relief to Rate 2/12 and 3/13 customers in the Bonnyville service area as those in other service areas, the harmonizing of Bonnyville Service Area's rates at this time is just and reasonable.[50]

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[48] Ibid, pp 19-24 and 50-51.

[49] EUB Decision 2003-052 (July 2, 2003), p. 1 and 4 (at Tab 6 of the FEU's Book of Authorities).

[50] EUB Decision 2003-090 (November 25, 2003), p. 8 (at Tab 7 of the FEU's Book of Authorities).

3.2.2.4 PowerStream Inc. and Aurora Hydro Connections Limited

54. A 2005 decision by the Ontario Energy Board approved an application by PowerStream Inc. and Aurora Hydro Connections Limited (AHCL) for PowerStream Inc. to acquire and amalgamate with AHCL. The OEB approved the proposed transactions based on several effects or benefits resulting from the proposed transactions, including opportunities for efficiencies and economies of scale and savings from the harmonization of rates.[51] In a subsequent rate case before harmonization of rates was implemented, the Board stated: “The Board is concerned about the rate disparities that continue to exist between Powerstream’s Richmond Hill and other customers, especially given the time that has elapsed since the acquisition of Richmond Hill Hydro by PowerStream’s predecessor companies.”[52]

55. When approving a subsequent application by PowerStream to harmonize four sets of rates for each area served by it, the OEB noted that “when rates are harmonized, some customers will experience an increase and others a decrease.” In that case, the largest increase for a typical residential customer was 2.5% while the largest decrease was 8.2%. For services for street lighting, the increase was 17% in one area. The OEB found the changes to be reasonable in the circumstances surrounding the harmonization of Powerstream’s rates.[53] This case is an example of a regulator accepting moderate rate increases in order to realize overall efficiencies.

3.2.2.5 Greater Sudbury Hydro Inc

56. In 2009 the OEB approved a post-amalgamation rate harmonization for Greater Sudbury Hydro Inc. The harmonization was expected to lead to a bill impact of nearly 30% for some smaller customers which the OEB accepted was an “unacceptable impact.” The

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[51] Exhibit B-9, Attachment 7.2: Ontario Energy Board, EB-2005-0254, Decision and Order dated September 19, 2005.

[52] Ontario Energy Board, RP-2005-0020, EB-2005-0409, Decision and Order dated April 28, 2006, at p. 8. At Tab 8 of the FEU’s Book of Authorities.

[53] Exhibit B-9, Attachment 7.2: Ontario Energy Board, EB-2007-0074, Decision and Order, dated July 26, 2007, at p. 4.

OEB therefore ordered a longer, three-year phase-in for that rate class as opposed to the two-year phase-in for the other rate classes.[54]

3.2.2.6 Canadian Niagara Power Inc. Distribution Rates

57. On July 15, 2009, the Ontario Energy Board approved an application from Canadian Niagara Power Inc. (CNPI) for the harmonization of distribution rates for two of its service areas. Each of the two service areas had separate rates. As recorded in the decision, "CNPI operates primarily from a single location, Fort Erie, with a single work force and allocates assets and services to each of these business units. CNPI proposed to harmonize the distribution rates of the Fort Erie and EOP service territories. CNPI's rationale for the harmonization was to eliminate duplicated efforts related to financial and regulatory reporting, regulatory compliance, and rate setting." Under the proposed harmonized rate design, costs with common cost drivers would be harmonized while cost drivers unique to the area of service would remain separate. In order to minimize the impact of this change, the proposal included the rebalancing of the revenue split between fixed charges and volumetric rates.[55]

58. The OEB approved the harmonization stating:[56]

> CNPI's rationale for the harmonization is appropriate. There are invariably impacts on customers from harmonization, positive and negative. In this case, the Board has noted CNPI's attempts to mitigate the negative impacts with the result that such impacts are not of concern.

59. In this case, the OEB recognized that there would be positive and negative rate impacts, but still determined that harmonization was appropriate.

3.2.2.7 East Hants and Shubenacadie Water Utilities

60. In 2010, the Nova Scotia Utility and Review Board approved an application to amalgamate the East Hants and Shubenacadie Water Utilities, which was proposed

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[54] Exhibit B-9, Attachment 7.2: Ontario Energy Board, EB-2008-0230, Decision and Order, dated December 1, 2009, at pp. 38-39.

[55] Ontario Energy Board EB-2008-0222, EB-2008-0223, at pp. 23 to 24. (Tab 9 of the FEU's Book of Authorities.)

[56] Ontario Energy Board EB-2008-0222, EB-2008-0223, at p. 24. (Tab 9 of the FEU's Book of Authorities.)

because the Shubenacadie Water Utility could not be sustained on its own.[57] The Board noted that both of the systems were operated by the same personnel, that from an administrative and financial view the proposed amalgamation made sense and that there was the potential for long-term efficiencies through spreading of costs over a larger customer base.[58] In response to concerns about increased rates for the East Hants utility due to the harmonization, the Decision states: "The Board noted that this situation is not unique and that other municipalities have proposed amalgamations to solve similar problems."[59]

3.2.2.8 Conclusion on Canadian Regulatory Authorities

61. While the FEU recognize that the cases referred to above relate to utilities in diverse circumstances, these cases do demonstrate that Canadian regulators have approved the harmonization of rates in a variety of circumstances, including where there are significant differentials in cost of service in the pre-existing service areas. The FEU submit that the weight of these authorities supports the principle of postage stamp rates and its application to the FEU.

[57] Exhibit B-9, Attachment 7.2: Nova Scotia Utility and Review Board, NSUARB-W-EHAN-R-09/2010 NSUARB, Decision dated February 18, 2010, at p. 18, para. 47.

[58] Ibid., at p. 19.

[59] Ibid., at pp. 20-21.

4.0 POSTAGE STAMP RATES ARE SUPPORTED BY RATE DESIGN PRINCIPLES

62. The FEU's proposed postage stamp rates are supported by accepted ratemaking principles based on Dr. Bonbright's widely accepted work, "Principles of Public Utility Rates." As described in section 9.5 of the Application, the FEU have used seven rate design principles based on those identified by Dr. Bonbright, consistent with previous rate design applications. These principles are: Fairness, Stability, Simplicity and Ease of Understandability, Customer Impact, Economic Efficiency, Competitiveness, and Recovering the Cost of Service.[60] The FEU submit that its proposed postage stamp rates appropriately balance the objectives of these principles and represent an improvement over the existing rates.[61]

63. The following sections will address the seven rate design principles, as follows:

(a) Fairness: The Harmonization of Rates is Fair and Equitable

(b) More Stable Rates

(c) More Simple and Easier to Understand and Administer Rates

(d) Customer Impact: Lower Rates for Vancouver Island and Whistler Service Areas

(e) Customer Impact: Mitigation of Rate Impacts to FEI and FEFN

(f) Efficiency

(g) Competitiveness

(h) Recovery of the Cost of Service

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[60] Exhibit B-3, Application, pp. 189 to 191. In the Commission's Reasons for Decision for Order G-45-11, the Bonbright principles are expressed as eight principles rather than 7. There is no material difference between the seven principles set out in FEU's Application and the eight set out in the Commission's Reasons for Decision for Order G-45-11. (Exhibit B-9, BCUC IR 1.16.1.)

[61] Exhibit B-9, BCUC IR 1.16.1.

4.1 Fairness: The Harmonization of Rates is Fair and Equitable

64. The principle of fairness in rate design is that costs should be recovered based on cost causation. For the reasons discussed in the following subsections, the proposed rate design for the Amalgamated Entity meets this principle as it ensures that the revenues to be recovered from each rate class are aligned with the cost to serve them.[62]

4.1.1 Postage Stamp Rate are More Consistent with Existing Rates

65. First, locational differences are generally not taken into account in the rates of the FEU, making the existing regional differences anomalous and less fair than the proposed postage stamp rates. Approximately 850,000 customers of FEI in the Lower Mainland, Columbia and Inland service areas already enjoy rates that generally do not distinguish based on location, including postage stamp delivery and commodity rates and midstream rates that are very similar. Postage stamp rates are also applied within the service areas of FEVI, FEW and Fort Nelson. The differences maintained for the smaller service areas of FEVI, FEW and Fort Nelson are in fact the only locational differences maintained in the FEU's rates and therefore inconsistent and less fair compared to a postage stamp rate design.

66. EES Consulting opines that it is not equitable to differentiate based on broad regional differences, while not differentiating based on more specific locations:[63]

> In reality, each customer on the system has a slightly different cost of service based on when they were connected, the location of the customer, the overall energy use, the load profile of the customer, etc. However, it would be impossible to set separate rates for each individual customer. For that reason customers are grouped into rate classes to reflect differences in usage patterns and connection costs. The question then becomes how far to carry the averaging of costs between customers on the basis of location. While there may be regional differences in costs, there are also differences in costs based on each customer's unique location on the system. We do not find it to be equitable to differentiate customer rates on the basis of broad regional differences while not differentiating on the basis of a more specific location or other factors.

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[62] Exhibit B-9, BCUC IR 1.7.2.3.

[63] Exhibit B-3-1, Appendix D-1, EES Consulting, "Natural Gas Cost of Service Review," page 5.

67. Thus, while the FEU recognize the variation in the cost of service based on the existing service areas, these variations should not be given much weight as costs differ for every single customer and for every potential region.[64] EES Consulting also writes:[65]

> In general, customers that were hooked up to the system long ago have lower costs than those hooked up more recently just because of when the facilities were built and the level of depreciation of facilities. Also customers in the more dense urban areas are less costly to serve than customers in more rural locations. Differences also exist because of the distance from the 3rd party transmission pipeline delivery points and because of the geographical terrain.

68. FEI serves approximately 850,000 customers in over 100 communities.[66] Each of these communities has its own unique attributes, including its geographic location and age. FEVI's postage stamp rates similarly apply to the approximately 102,000 customers it serves in approximately 40 different communities.[67] While there are undoubtedly variations in costs and other attributes in each of the communities, the variations are smoothed over in the existing postage stamp rates within each region. There is therefore nothing unique or special about cost variations that exist amongst the existing service areas. In the FEU's submission, this means that it is fairer to implement postage stamp rates and remove the last remaining regional distinctions in rates.

69. At a more general level, the proposed postage stamp rates would also be more consistent with utility rates in this Province, past Commission decisions and government policy. As discussed above in section 3 of this submission, while FEI has moved towards postage stamp rates over time, postage stamp rates have been in place since 1962 for BC Hydro and are also in place for FortisBC Inc. The Commission has rebuffed a complaint by the District of Chetwynd regarding postage stamp rates and confirmed the postage stamp rate for the ski resort community of Big White in Fortis BC Inc.'s service area. Under postage stamp rates, the costs of capital projects approved by the Commission are rolled into rates and not attributed to the particular community or communities that benefit from

[64] Exhibit B-15, BCUC IR 2.11.1.

[65] Exhibit B-3-1, Appendix D-1, EES Consulting, "Natural Gas Cost of Service Review," page 6.

[66] Exhibit B-3, Application, p. 22.

[67] Exhibit B-3, Application, p. 40.

the project. The evidence also shows that provincial government policy is supportive of postage stamp rates.

70. The FEU therefore submit that postage stamp rates for the FEU will be more consistent with the postage rates already in place throughout the Province, which has been supported by both Commission decisions and government policy. Moreover, in the FEU's submission, given the predominance of postage stamp rates, continuing to maintain the rate differences for the smaller service areas of the FEU is less fair and no longer justified.

4.1.2 Existing Service Areas are a Result of Corporate History

71. The current service areas of the FEU are an artefact of the FEU's growth by acquisition and are not the result of a considered rate design for an amalgamated entity.[68] EES Consulting recognizes that "the current regional differences in delivery rates… [for the FEU]…do not necessarily reflect the same regional separation that would occur based on operating and cost differences alone."[69]

72. Section 3 of the Application describes the history of the growth, acquisition and mergers of the various natural gas distribution companies in the past that have led to the current corporate structure of the FEU. As described there, the FEVI, FEW and Fort Nelson regions reflect historically separate natural gas distribution companies that have been acquired. While the existing regional differences were appropriate in the past when there were separate corporate entities, the FEU submit that the regional differences are anachronistic and should not be a driver of rate design. As held by the Board in the Newfoundland and Labrador Hydro case discussed above, the Commission's mandate is to set rates on a prospective basis and the historical development of the natural gas distribution systems should not be a relevant factor in determining whether to implement postage stamp rates. In the FEU's submission, the most appropriate rate design for the amalgamated entity is a postage stamp rate, which would be consistent with BC Hydro's

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[68] Exhibit B-3, Application, pp. 12-13, section 3 generally, and p. 105.
[69] Exhibit B-3-1, Appendix D-1, EES Consulting, "Natural Gas Cost of Service Review," p. 8

rates that are postage stamped across similar areas and FEI's own broad postage stamp rates applied over most of the Province.

4.1.3 Utilities are Under Common Ownership, Management and Operation

73. While the existing regional distinctions reflect corporate history, postage stamp rates would properly reflect the present day reality of the common ownership, management and operation of the FEU. With the acquisition of Fort Nelson Gas Ltd. in 1985 and Centra Gas BC Inc. and Centra Gas Whistler Inc. in 2002, all of what are now known as the FEU came under common ownership.[70] With common ownership, came greater integration of the management and operation of the utilities so that today the FEU are not only commonly owned, but share a common management structure and essentially operate as one entity.[71]

74. As a result of this integration, all customers of the FEU have realized savings. In addition, integration requires many costs of the FEU to be allocated to customers based on common factors as reflected in the FEU's Shared Services Agreements.[72] Thus, whether a customer is located in Victoria, Kamloops or Fort Nelson, the same allocation of common costs are being made. Postage stamp rates would negate the need for the allocation of service costs[73] and properly reflect the reality that all FEU customers are effectively provided with the same service by one utility.

4.1.4 Customers are Served by an Operationally or Physically Interconnected System

75. Harmonized rates would also reflect the fact that the customers of the FEU are served by an operationally or physically interconnected system. Over time, the FEU's systems have become increasingly interconnected physically and operationally, including greater integration of existing facilities and processes and installation of new facilities that

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[70] Exhibit B-3, Application, pp. 23 to 24.
[71] Exhibit B-3, Application, p. 51.
[72] Exhibit B-14, Robinson IR 2, Attachment 6, KPMG Shared Services Review.
[73] Exhibit B-3, Application, pp. 132-133.

benefit all of the utilities.[74] The FEU stated the following in Exhibit B-15, BCUC IR 2.11.2:

> The FEU do consider that FEVI and FEW have a high level of physical interconnection and share a high level of facilities with FEI, while FEFN shares facilities to a much lesser extent. For example, FEVI is directly connected to and relies on FEI's Coastal Transmission System (CTS) for transport of all its gas supply. FEW directly connects to FEVI's transmission system and therefore indirectly also shares the use of CTS. FEW also shares the use of Tilbury and FEI's Southern Crossing Pipeline (SCP) / Interior Transmission System (ITS) as it is part of FEI's gas portfolio. FEVI, FEW and FEI all share the use of the FEVI transmission system and Mt. Hayes storage facility for storage and delivery services. Although FEFN is not directly connected to any of the FEU's facilities other than the lateral connection to Westcoast's system, FEFN still benefits from being part of the overall midstream portfolio as discussed in responses to other information requests, such as BCUC IR 1.47.1 and 1.47.2.
>
> The FEU manage and operate on a fully integrated basis as a single system and have common management control and decision making systems, common distribution, transmission, and business support operations, and optimize the supply of natural gas based on managing the needs of a portfolio of resources that minimizes costs for all customers. The FEU do not track the portion of assets that are shared by each of the utilities because of the integrated management and operation of the utilities and so cannot provide percentages of shared assets. However the following are a few examples that illustrate the sharing of some of the significant elements of the combined system:
>
> - FEVI's Mt. Hayes LNG & Transmission system – FEI (and indirectly FEW) – has firm rights to two thirds (68%) of Mt. Hayes capacity and relies on approximately the same portion of the FEVI transmission system for redeliveries to the Lower Mainland whether directly or by displacement.
>
> - FEI's Coastal Transmission System (CTS) - FEVI (and indirectly FEW) has firm rights on approximately 11% of the capacity on the CTS (approximately 148/1350 TJ/d) that otherwise serves FEI's Lower Mainland customers.

[74] Exhibit B-15, BCUC IR 2.10.1.

- FEI's Southern Crossing Pipeline (SCP) and Interior Transmission System - Primarily serves FEI's Inland and Lower Mainland service areas and indirectly serves FEW's service area. Following amalgamation and a move to a single gas portfolio, it would also be used to serve customers in the territory currently served by FEVI.

76. The level of integration underscores the appropriateness of postage stamp rates. EES Consulting opines:[75]

> Postage stamp pricing better reflects the fact that utility systems have a high level of interconnection, and facilities are most often shared among large groups of customers. Facilities closer to the customer, like distribution facilities, are more closely tied to local groups of customers, while facilities upstream from the customer, like transmission, are generally used by all customers on the system. When the FEU service areas had separate ownership they were operated as stand-alone entities and needed to rely on their own facilities to deliver gas to customers. Each separate utility had postage stamp rates within their service areas. The acquisition of the different utilities led to operational efficiencies and resulting cost savings. This includes greater integration of existing facilities and installation of new facilities that benefit the entire utility. As the systems become more and more integrated, the application of postage stamp pricing across all regions becomes more appropriate.
>
> With a continuation of regional rates, any facilities that are used for multiple regions would need to have a special allocation arrangement to share the costs equitably. These allocations are already in place for existing facilities, such as the Mt. Hayes storage facility. While it is possible to continue with this approach, the planning and sharing of costs for facilities that benefit customers in multiple regions is simplified under a postage stamp pricing approach, and is not open to contention in the allocation among the regional customers.

77. Thus, as the systems become more and more integrated, the expansion of FEI postage stamp pricing across the remaining approximately 100,000 customers (FEVI, FEW and FEFN customers) becomes more appropriate. Postage stamp rates better reflect the fact that FEU's systems have a high level of interconnection, and that facilities are shared

[75] Exhibit B-3-1, Appendix D-1, EES Consulting, "Natural Gas Cost of Service Review," pp. 6-7.

among large groups of customers.[76] As customers are served by the same system, all similarly situated customers should receive service at the same rate regardless of location.

4.1.5 FEI, FEVI, FEW and FEFN are Similar

78. Finally, the FEI, FEVI, FEW and FEFN service areas share more similarities than differences and do not have unique enough features to warrant a regional rate structure. As discussed above, all the regions are served by effectively one company and one system. They also all share the same provincial government, rate regulator and economic and policy climate at a provincial level. Beyond these essential similarities, the response to BCUC IR 2.13.1 provides a list of the similarities amongst the service areas based on the evidence in this proceeding, including similarities in the nature of the rate base, the customer makeup, gas supply administration, operational characteristics and the overall cost structures of the regions.[77] The list could be expanded to include other factors such as the following:

(a) Administration and billing costs are not significantly different.[78]

(b) The load factors by class are similar for each of the existing service areas.[79]

(c) The timing of the peak demand is similar in each delivery area.[80]

(d) Each service area has similar load duration curves.[81]

(e) Each service area has similar opportunities to reduce consumption.[82]

79. In addition, over time the overall cost structures of the service areas will converge as the assets in the FEVI and FEW service areas depreciate and more asset replacement occurs within FEI and FEFN.[83]

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[76] Exhibit B-15, BCUC IR 2.10.1.
[77] Exhibit B-17, BCUC IR 2.13.1 (corrected).
[78] Exhibit B-9, BCUC IR 1.149.1.
[79] Exhibit B-9, BCUC IR 1.150.1.
[80] Exhibit B-9, BCUC IR 1.150.2.
[81] Exhibit B-9, BCUC IR 1.153.1.
[82] Exhibit B-15, BCUC IR 2.8.3

80. FEU's expert evidence from EES Consulting has considered the various differences and similarities between the regions and opines that postage stamp rates are the most appropriate rate design. Some of the factors that are relevant to determining the appropriateness of regional rates would include the interconnectedness and use of common facilities, the similarity of the service offered, the similarity of the customers' consumption patterns, the ownership structure, how the utility is operated, and the existence of unique facilities in a particular region.[84] As stated in response to BCUC IR 2.6.4 (Exhibit B-15):

> EES Consulting looked at these factors in determining whether or not it was appropriate to postage stamp the rates for the FEU. The separate rates were appropriate when there was different ownership of the utilities. Under common ownership, the system has become more integrated in terms of the use of the existing facilities, the addition of new facilities, and the operation of the system. Further, EES Consulting did not see any unique facilities or differences in the customer base that would warrant a continuation of regional rates. Given these findings, EES Consulting concurred that postage stamped rates were appropriate for the FEU.

81. EES Consulting's conclusions have not been challenged by any evidence in this proceeding. The FEU submit that overall the service areas are more similar than they are different and that there are no features of the regions that are sufficiently unique to warrant regional rates.

82. Further, while there are some variations at a regional level, the FEU submit that analyzing differences between the regions is an essentially flawed exercise since the regional numbers will gloss over the differences within each region and, in particular, the diversity of the large FEI customer base. For instance, while it is true that FEVI in total has a lower average use per customer than FEI, FEI has almost three times as many customers that have similar annual usage amounts as FEVI.[85] Further, use rates vary within FEI, as demonstrated by the following table which shows the difference in use

[83] Exhibit B-17, BCUC IR 2.13.1 (corrected).
[84] Exhibit B-15, BCUC IR 2.6.3.
[85] Exhibit B-15, BCUC IR 2.39.2.

rates across the Lower Mainland, Inland and Columbia service areas. For reference, the table also includes use rates for FEVI, FEW and Fort Nelson.[86]

Service Area	2011F Residential Use Rate
Lower Mainland	99
Inland	75
Columbia	81
FEVI	50
FEW	102
Fort Nelson	141

83. While FEI Mainland has an average residential use rate of 92 GJ,[87] the total FEU has a marginally lower average residential use rate of 85.6 GJ.[88]

84. Moreover, there is variation within each of the service areas listed above. The following table shows the variety of use rates amongst various communities within the Lower Mainland service area.[89]

2011 Actual Rate 1	Consumption (GJs)	Premises	UPC (GJ)
Abbotsford	2,746,293	29,026	94.6
Chilliwack	1,821,464	23,823	76.5
Hope	175,180	2,276	77.0
New Westminster	813,661	8,342	97.5
Surrey	10,807,224	100,273	107.8
Vancouver	10,617,435	93,739	113.3
West Vancouver	2,071,535	12,379	167.3

85. The use rates amongst municipalities in the Lower Mainland shown above range by 90 GJ between the lowest and the highest. As postage stamp rates are currently applied across these various use rates, there is no reason why the particular variation in use rates in FEVI or any other service area should be a barrier to extending postage stamp rates.

86. As another example, while the FEVI and FEW systems are newer on average than the FEI system, there are areas within FEI that are newer than the average, such as in Surrey

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86 Exhibit B-9, BCUC IR 1.146.1 and 1.147.1.

87 Exhibit B-9, BCUC IR 1.147.1.

88 Total of 74.9 PJs (Exhibit B-3, Application, Table 4-1, p. 54), divided by 877,036 residential customers (Exhibit B-15, BCUC IR 2.39.2).

89 Exhibit B-15, BCUC IR 2.32.2.

and Kelowna where system growth has been more extensive.[90] The same is true for customer demographics. Customers are not homogenous within FEI but vary greatly in and amongst the service areas, and some areas may be quite similar to areas within FEVI, FEW and Fort Nelson. For example, income levels and housing costs in some communities served by FEI are similar to those in communities within FEVI and FEW.[91]

87. As a final example, the fact that Whistler contains a ski resort and has recreational properties is not a unique attribute. Other service areas within the FEU also have a significant number of recreational properties and similar characteristics. Examples include Big White (Inland service area), Mount Washington (FEVI service area) and Fernie (Columbia service area).[92] All of these areas enjoy the benefits of postage stamp rates today.

88. There is also no evidence that regional rates are the appropriate rate design approach to address particular types of customers, such as low consumption or recreational properties that exist in FEVI, FEW and parts of FEI. To the contrary, as there is diversity within each region, regional rate structures are a blunt instrument to target a particular type of consumer. For example, it is inaccurate to consider FEW as consisting of only recreational properties. A significant portion of FEW's sales, for instance, come from large resort hotels in the LGS customer segmentation whose consumption is more characteristic of a year round commercial customer.[93] In fact, more than half the sales volume of FEW comes from the LGS customer segment.[94]

89. The FEU therefore submit that overall the regions are more similar than they are different and that there are no unique features of any region that warrant a regional rate structure. This conclusion is supported by the unchallenged expert evidence of EES Consulting. As such, the FEU submit that postage stamp rates are the most fair rate design for FEI Amalco.

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[90] Exhibit B-9, BCUC IR 1.82.1; Exhibit B-15, BCUC IR 2.35.2.
[91] Exhibit B-15, BCUC IR 2.45.3.
[92] Exhibit B-15, BCUC IR 2.45.3.
[93] Exhibit B-15, BCUC IR 2.39.4.
[94] Exhibit B-3-1, Appendix H-7, Schedule 7, line 3, Sales Volume (TJ).

4.1.6 Summary on Fairness Principle

90. For the reasons discussed above, the FEU submit that postage stamp rates reflect a considered rate design approach from a fairness and equity perspective that is superior to the regional distinctions currently in place that are rooted in corporate history. Postage stamp rates appropriately reflect the fact that all FEU customers are served by essentially the same utility with the same operationally or physically interconnected system and are more consistent with the current postage stamp rates in place in the Province and with government policy. The FEU therefore submit that harmonized rates are the most equitable and fair approach for the Amalgamated Entity.

4.2 More Stable Rates

91. Rate stability is a recognized rate design principle that refers to the stability of the rates themselves, with a goal of minimum unexpected rate increases that are seriously adverse to existing customers.[95] Aligned with this principle, a key benefit of amalgamation and postage stamp rates is that they will result in more stable rates over time for all customers, especially for the smaller service areas of FEVI, FEW and FEFN.[96]

92. As stated in the Application, once the full rate impact of postage stamping has been accounted for, common rates across a combined entity will tend to stabilize rate levels by providing a broader customer base to absorb localized investments in infrastructure, localized economic difficulty and other factors affecting throughput without generating spikes in rates.[97]

93. EES Consulting addresses this point in terms of the impact of capital additions in its expert report as follows:[98]

> With postage stamp pricing, capital additions are spread out among all customers, making the impact less volatile. Because capital costs are often large and infrequent in nature, if they are directly assigned to a smaller group of customers, the impact will be large

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[95] Exhibit B-3, Application, Section 9.5.1; Bonbright, Principles of Public Utility Rates, p. 383.

[96] Exhibit B-3, Application, section 6.3.2.

[97] Bonbright, Principles of Public Utility Rates, p. 383. (At Tab 11 of the FEU's Book of Authorities.)

[98] Exhibit B-3-1, Appendix D-1, EES Consulting Inc., "Natural Gas Cost of Service Review," p. 7.

> at one given time. Postage stamping allows the impacts of capital projects to occur on a more gradual basis.

94. This reasoning was expanded on in information requests, as the FEU noted that at any given time there are going to be neighbourhoods within a utility that are old and established while other neighbourhoods are new and facing significant growth. This averaging of costs among various neighbourhoods and regions is one of the benefits of postage stamp rates. Postage stamping provides stability in rates when specific areas are facing different costs at different times because of the timing of projects, the "lumpiness" of capital improvements and the population and housing density of different areas, among other factors.[99]

95. A key benefit of the stability of postage stamp rates would be the resolution of the current vulnerability of FEVI, FEW and FEFN to long-term rate instability. For FEVI and FEW, this vulnerability is in part the result of their relatively high rate base per customer.[100] Because FEVI and FEW have a higher rate base per customer when compared to FEI, their rates are more susceptible to the impact of the implementation of large capital projects. In addition, FEVI, FEW and FEFN are all challenged by having a less diverse customer base compared to that of FEI. As stated in the Application, the top 10 highest consuming FEVI customers account for approximately 63 percent of FEVI's total throughput and 16 percent of the total revenues. For FEW, this ratio is 18 percent of total throughput and 21 percent of total revenues, whereas for FEFN this ratio is 17 percent of total throughput and 11 percent of total revenue. This suggests that the loss of a major customer for one of these smaller utilities would have a material impact on both throughput and revenue.[101]

96. Amalgamation and postage stamp rates will resolve these issues by providing a larger and more diverse customer base over which to spread costs, leading to more stable rates in the long term. The relevance of this benefit to Fort Nelson in particular is discussed in subsection 6.3 below.

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[99] Exhibit B-9, BCUC IR 1. 85.2.

[100] Exhibit B-3, Application, pp. 75 to 78.

[101] Exhibit B-3, Application , p. 77.

97. The FEU submit that the proposed postage stamp rates are beneficial when considered under the principle of rate stability and that the stability of rates for FEVI, FEW and FEFN is a key benefit of the proposed amalgamation.

4.3 Simplicity and Ease of Administration

98. The practical attributes of a rate, such as its simplicity and the ease with which it can be understood and administered, is also an accepted rate design principle.[102] Considered under this principle, the implementation of common rates for FEI Amalco will result in rates that are simpler, more easily understood by customers and more easily administered by FEI Amalco compared to the existing rates.

99. As stated by Dr. Bonbright in his discussion on the "Criteria of a Sound Rate Structure," the practical attributes of a sound rate structure include "the related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability and feasibility of application".[103] As discussed above, the Commission has previously recognized the importance of the practical attributes associated with common rates in Letter No. L-24-04 regarding the District of Chetwynd, which noted the importance of the factors of administrative simplicity and understandability.[104]

100. There is currently a significant disparity and complexity in the rates across the FEU. The complexity of the different rates extends beyond rate levels to the different rate schedules and rate categories of FEI Mainland, FEVI, FEW and FEFN.[105] The rate schedules vary from the 26 diverse schedules of FEI[106] to the single rate schedule applied by the FEW. The rate categories of FEI include a Basic Charge, Delivery Charge, Midstream Charge and Commodity Charge. FEVI, however, has a bundled rate with Basic Charge and Energy Charge. FEW has a Basic Charge, Delivery Charge and Gas Cost Recovery Charge. FEFN, on the other hand, has a minimum daily Charge and declining block

[102] Exhibit B-3, Application, section 9.5.1.
[103] Exhibit B-3, Application, p. 115. Also see Tab 11 of the FEU's Book of Authorities.
[104] BCUC Letter No. L-24-04, dated April 23, 2004, at Tab 1 of the FEU's Book of Authorities.
[105] Section 3 of the Application describes the rate structures for each of the entities.
[106] Exhibit B-3, Application, pp. 31 to 35.

consumption based delivery and commodity rates.[107] While each of FEI, FEVI and FEW has a fixed or basic charge, none of the charges are the same.[108]

101. Implementing common rates will result in a single set of rate schedules and rate categories with the same rates available to all customers. This will provide a simpler rate structure with reduced administration requirements on an ongoing basis. A common rate structure will also lead to reduced information requirements for customers, including a decrease in the volume of communication activities related to rate changes where currently separate materials are produced for each of the FEU companies. Common rates will also reduce the activities and billing procedures that are currently required to maintain the various rate classes in the billing system.[109]

102. Postage stamp rates are therefore beneficial as they are simpler, easier to understand and easier to administer compared to regional rates.

4.4 Customer Impact: Lower Rates for FEVI and FEW

103. The fourth rate design principle is that of customer impact. A beneficial consequence of amalgamation and the harmonization of rates is that it will result in lower rates for customers in the FEVI and FEW service areas. The higher rates for FEI and FEFN customers are addressed in the following section.

104. As detailed in the Application and information responses, FEVI and FEW currently have much higher rates than FEI, despite being served by the same integrated system under common ownership, management and operation. Based on the 2013 rates for typical residential customers proposed in the FEU's 2012-2013 Revenue Requirements Application ("RRA"), customers located in FEVI's and FEW's service areas will be paying 45 percent and 64 percent higher than FEI, respectively.[110] Based on an annual consumption of 90 GJs a year, FEVI customers will pay approximately $438 dollars more

[107] Exhibit B-3, Application, p. 115.
[108] Exhibit B-15, BCUC IR 2.39.1, 2.39.3 and 2.39.7
[109] Exhibit B-9, BCUC IR 1.83.1.
[110] Exhibit B-3, Application, p. 73.

than an FEI (Mainland) customer, while FEW customers will pay approximately $629 dollars more.[111]

105. FEVI is particularly challenged due to the cessation of government subsidies, including the loss of the Royalty Revenues arrangement on December 31, 2011 and the repayment of the federal/provincial repayable contributions. FEVI's corporate and regulatory history, including the effect of the *Vancouver Island Natural Gas Pipeline Act Special Direction*,[112] has been detailed in the Application[113] and information responses.[114] FEVI has retained a balance in its RSDA to temporarily mitigate the effect of the loss of government subsidies. Once the balance in the RSDA reaches zero, however, FEVI customers face a rate increase in the range of 20%, compounding the rate disparity with FEI and FEFN customers.[115]

106. These higher rates result in challenges for FEVI and FEW on a stand-alone basis. Section 4 of the Application describes the operating trends that are negatively affecting the FEU, such as declining use rates. FEVI and FEW are more susceptible to the effects of these trends as they have a lower customer base over which to spread their costs. The higher rates in FEVI and FEW will also pose a higher business risk for connecting new customers to the system and keeping existing customers on the system, as alternative forms of energy may have a competitive cost advantage. Further, the cost of gas could rise due to changes in the demand and supply mix, increasing the business risk.[116]

107. Combining the FEVI and FEW rate bases and customers with FEI, including FEFN, through amalgamation will result in FEVI's and FEW's higher fixed costs being spread over a larger customer base, thereby reducing natural gas rates within the smaller service areas and putting those customers on an equal footing with the majority of the FEU's

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[111] Exhibit B-3, Application, Table 4-7, p. 73. FEVI Differential: ($15.725 - $10.859) * 90 GJs = $437.94. FEW Differential: ($17.850 - $10.859) * 90 GJs = $629.19.

[112] OIC No. 1510 (Dec. 13, 1995), pursuant to the *Vancouver Island Natural Gas Pipeline Agreement Act*, R.S.B.C. 1996, c. 474.

[113] Exhibit B-3, Application, Section 3.3, pp. 37 to 40 and section 4.3, pp. 73 to 75.

[114] Exhibit B-9, BCUC IR 1.21.1.

[115] Exhibit B-3, Application, p. 74.

[116] Exhibit B-9, BCUC IR 1.61.1.

natural gas customers in the Province. All else equal, this will help FEVI and FEW retain customers and mitigate the potential for a declining customer base and lower throughput levels which would otherwise lead to further rate increases.[117]

108. The FEU therefore submit that the lower rates for FEVI and FEW are a significant benefit of amalgamation and postage stamp rates.

4.5 Customer Impact: Mitigation of Rate Impacts to FEI and FEFN

109. Under the Customer Impact principle, the rate impacts to FEI and FEFN customers should also be considered. Without any mitigation, the proposal to amalgamate and implement postage stamp rates will result in an annual bill impact of approximately 5% for current FEI Mainland residential customers and approximately 55% FEFN residential customers. Based on regional annual consumption, this results in an annual bill impact of approximately $54 for FEI Mainland Customers and $542 for FEFN customers.[118] In the submission of the FEU, while these rate impacts should be mitigated, they are not sufficient to outweigh the benefits of postage stamp rates including the fairness, stability, and simplicity of postage stamp rates and the benefit of lower rates for FEVI and FEW customers as described above.

110. The FEU have proposed to mitigate the bill impacts through a 15-year phase-in for FEFN and a three-year phase-in for FEI Mainland.[119] The following subsections discuss the FEU's proposed phase-in options, as well as other approaches that were canvassed in the proceeding.

4.5.1 Proposed Fort Nelson Phase-in Approach

111. In order to mitigate the rate increase to Fort Nelson customers, the FEU propose that FEI Amalco phase-in the total amalgamation and postage stamp-related rate increase over 15

[117] Exhibit B-3, Application, pp. 113-114; Exhibit B-15, BCUC IR 2.6.3.

[118] Exhibit B-3-1, Application, Section 8.4.2 and Appendix J-4. For further detailed information on the rate impacts, see Exhibit B-9-1, BCUC IR 1.98.1 and Exhibit 17, Errata, Tab 6, Attachment to BCUC IR 1.98.1.

[119] The bill impacts per rate class are detailed with and without phase-in in the responses to BCUC IR 1.93.3 and 1.93.4 (Exhibit B-9).

years. A detailed description of the phase-in approach is provided in the Application[120] and in information request responses.[121] In summary, this approach is as follows:

- In the first five years of the phase-in, Fort Nelson customers would be shielded from the initial common rate related increase.
- After the initial five year period, in 2019 a portion of the postage stamp and amalgamation-related cost of service increase will be flowed through to Fort Nelson, with an approximate 5.5% annual burner-tip bill impact for typical residential customers.
- The approximate 5.5% annual increase would continue through to 2027 and in 2028 (i.e., Year 15) Fort Nelson customers would reach rate parity with the other customers of the Amalgamated Entity.

112. The shortfall arising from the phase-in of the Fort Nelson rate increases for the 15 year period will be met through a portion of the RSDA funds.

113. While the FEU recognize that Fort Nelson is opposed to the FEU's proposed postage stamp rates, the 15 year phase-in option was voted on and approved as the preferred mitigation option during the Northern Rockies Regional Municipality meeting on September 20th, 2011.[122] No alternative approaches were raised in information requests or in intervenor evidence.

114. The FEU submits that this phase-in approach appropriately mitigates the impacts to the Fort Nelson customers. The appropriateness of extending postage stamp rates to Fort Nelson in particular is discussed in section 6.3 below.

4.5.2 Proposed FEI Phase-In Approach

115. The FEU propose to return the balance in the RSDA (i.e. after removing the amount required for Fort Nelson)[123] to FEI Mainland customers over a period of three years. Under this approach, the RSDA balance would be amortized equally over three years to all non-bypass FEI Mainland customers, providing a two-step rate increase to achieve

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[120] Exhibit B-3, Application, pp. 165-168 and Exhibit B-3-1, Appendix J-1 Schedule 34.

[121] Exhibit B-9, BCUC IR 93.4, 96.1 and 96.2, Exhibit B-15 BCUC IR 2.42.1.

[122] Exhibit B-3, Application, p. 226.

[123] Based on the current forecasted balance in the RSDA at the end of 2013 of $90.3 million before tax and after deducting the FEFN Allocation of $18.9 million. (Exhibit B-3, Application, p. 168.)

common rates. All else equal, returning the RSDA in 3 equal annual instalments is forecast to limit delivery rate annual bill increases from amalgamation to 3.3% in 2014.[124] There will be no further increases resulting from amalgamation in 2015 and 2016. In 2017, rates are forecast to increase a further 2.0%, for a total increase of 5.3% which would fully transition FEI customers to the amalgamated rates. This three-year phase-in approach will result in a substantial mitigation of the initial rate impact and prolong the length of time that FEI Mainland customers will benefit from the disbursement of the RSDA, while limiting fluctuations in customers' annual bills.[125]

116. Under the FEU's proposed approach, the rate decreases to FEVI and FEW would be realized immediately. FEVI and FEW customers have been paying substantially higher rates for many years and, in the FEU's submission, it is appropriate that they realize the benefits of postage stamp rates without any delay. In addition, realizing the rate decreases immediately is important in order to facilitate the migration of FEVI and FEW customers into the rate schedules available to them under FEI Amalco. If the rate decreases are phased-in, FEVI and FEW customers will not experience the true impact of the rate schedules, hampering their ability to find the appropriate schedule. Having the FEVI and FEW customers settle in to the FEI Amalco rate schedules as soon as possible is important so that FEI Amalco can prepare its next rate design application based on the correct customer information.

117. Furthermore, the balance in the RSDA already provides a means of substantially mitigating the rate impacts to FEI Mainland customers, with a 3.3% increase in year 1 and a 2.0% increase in year 4. In response to information requests, the FEU have described phase-in options in which both rate decreases to FEVI and FEW and rate increases to FEI Mainland would be phased-in so that all three entities would reach rate parity over a three or five-year period.[126] The annual bill impacts of the FEU's proposed approach and these two other approaches are shown in the table below.

[124] Exhibit B-3, Appendix J-3.

[125] Exhibit B-3, Application, p. 169-171.

[126] Exhibit B-9, BCUC IR 1.24.2; Exhibit B-15, BCUC IR 2.57.2.2; Exhibit B-13, CEC IR 2.14.1.

Phase-In Impacts - Residential Customers	2014	2015	2016	2017	2018	2019
FEI - Lower Mainland						
Phase-In Approach proposed in Application						
Annual Bill Impact	3.3%	0.0%	0.0%	2.0%		
Three Year Phase-In Approach as per BCUC IR 2.57.2.2*						
Annual Bill Impact	1.5%	1.3%	1.3%	1.3%		
Five Year Phase-In Approach as per BCUC IR 2.57.2.2*						
Annual Bill Impact	1.1%	0.8%	0.8%	0.8%	0.8%	0.8%
FEVI						
Phase-In Approach proposed in Application						
Annual Bill Impact	-25.5%					
Three Year Phase-In Approach as per BCUC IR 2.57.2.2*						
Annual Bill Impact	-3.3%	-7.4%	-7.4%	-7.4%		
Five Year Phase-In Approach as per BCUC IR 2.57.2.2*						
Annual Bill Impact	-0.8%	-4.9%	-4.9%	-4.9%	-4.9%	-4.9%
FEW						
Phase-In Approach proposed in Application						
Annual Bill Impact	-36.0%					
Three Year Phase-In Approach as per BCUC IR 2.57.2.2*						
Annual Bill Impact	-5.2%	-10.3%	-10.3%	-10.3%		
Five Year Phase-In Approach as per BCUC IR 2.57.2.2*						
Annual Bill Impact	-1.8%	-6.8%	-6.8%	-6.8%	-6.8%	-6.8%

*Exclusive of RSDA, RSAM & MCRA Rider Impacts

118. As shown above, the phasing in of the rate decreases over a three-year period results in an annual rate impact to FEI Mainland residential customers of between 1.3% and 1.5% depending on the year, while a five-year option results in an annual rate impact of between 0.8% and 1.1% depending on the year. These annual impacts could be reduced

yet further with the use of the balance in the RSDA.[127] While there is no end to the options available to mitigate rates, a balance must be struck between the need to mitigate the rate impacts of postage stamp rates and the benefits of fully implementing postage stamp rates, especially for FEVI and FEW customers. In the FEU's submission, the goal should be to mitigate the impacts to FEI customers with the least delay and complexity over the transition. Under the FEU's proposed approach using the RSDA balance, this goal is achieved.

119. The FEU therefore submit that there is no need or reason to delay the benefits of postage stamp rates to FEVI and FEW customers who have been paying substantially higher rates for many years. The FEU submit that phasing-in the decreases to FEVI and FEW provides no substantial improvement of the mitigation for FEI Mainland customers, would unnecessarily delay the benefits of postage stamp rates, result in unnecessary complexity over the transition and would unduly hamper the final migration of FEVI and FEW customers into the FEI Amalco rate schedules. If the Commission were to determine that a phase-in of the FEVI and FEW rate decreases is appropriate, the FEU submit that the phase-in should not be any longer than 3 years.

120. The FEU submit that several of the other phase-in options canvassed during the proceeding are also not reasonable.

(a) In response to a request from the CEC, the FEU modeled a phase-in option similar to the FEU's alternative approaches except over a seven-year time frame.[128] As even a three-year option materially mitigates the rate impact to FEI customers, the FEU submit that a seven-year phase-in option delays the full implementation of postage stamp rates with no material benefit to customers and is not justified.

(b) The FEU were requested to model a phase-in option that would involve freezing FEVI and FEW rates, while all revenue requirement increases were applied to FEI

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[127] Exhibit B-15, BCUC IR 2.57.2.2.
[128] Exhibit B-13, CEC IR 2.14.5.

rates until they reached parity.[129] This option would take an inordinate length of time to reach parity and the FEU submit that the length of delay in implementing postage stamp rates and its full benefits in this scenario is not reasonable. In addition, by holding FEVI and FEW rates at their current levels, it would be difficult to apply common rate classes across all the service areas, and would delay appropriate migration between classes and service offerings. This in turn will delay the ability to propose future rate design or rebalancing efforts for the combined service areas.[130] The FEU therefore submit that this type of option is not reasonable.

(c) Another scenario suggested was where the revenue requirements for each of the entities is combined, but the existing rate structures and current rates are maintained and any changes to revenue requirements in the future would be applied across the rates in all service areas at the same amount.[131] This scenario may actually increase the rate disparity across the FEU and perpetuates the requirement to maintain separate regulatory books for the four entities, thus minimizing the administrative efficiencies gained through rate harmonization. More fundamentally, the FEU believe that it is inconsistent to approve incremental changes on a postage stamp basis without first transitioning to a common rate.[132] The FEU therefore submit that this proposal is not reasonable.

121. The FEU submit that these scenarios are inferior to the FEU’s proposed and alternative phase-in scenarios and should not be implemented by the Commission.

4.5.3 Conclusion on Mitigation of Rate Impacts

122. While rate stability is an important attribute of all rates, rate design changes are required from time to time and rate impacts are an inevitable result of such changes. In the FEU’s submission, the proposed mitigation strategy sufficiently preserves the stability of rates and would enable a smooth transition to postage stamp rates. With the mitigation

[129] Exhibit B-9, BCUC IR 1.24.2.
[130] Exhibit B-15, BCUC IR 2.57.2.1.
[131] Exhibit B-9, BCUC IR 1.93.6.
[132] Exhibit B-9, BCUC IR 1.93.6.1.

proposed, the FEU submit that the rate impacts to FEI and FEFN customers are outweighed by the many positive attributes of postage stamp rates, including considerations of fairness, stability and simplicity and the rate decreases to other customers as discussed above.

4.6 Economic Efficiency

123. Economic efficiency is defined as a state in which resources are optimally allocated to customers so as to minimize waste and inefficiencies.[133] The proposed postage stamp rates are consistent with the economic efficiency principle since the proposed rates are based on the current FEI rate design, which is efficient and has been reviewed and approved by the Commission in several proceedings.[134]

124. The FEU's existing rates are already efficient since the commodity cost is set at market-based incremental costs, and the delivery rates largely recover fixed costs. For delivery charges, the FEU face a large amount of fixed costs for the existing transmission, storage and distribution facilities that are in place today. As most of the delivery costs are fixed, reduced consumption by customers will not lead to reduced costs on the delivery system.[135] The cost of gas, however, is directly related to consumption and can be reduced by energy efficiency and conservation.[136] In the case of the FEU, the cost of gas is already placed at the marginal cost to the utility, reflecting an efficient rate design.[137]

125. The proposed postage stamp rates are more efficient then the existing rates in at least two ways:

(a) Applying FEI's rates will increase the basic charge in FEVI, FEW and Fort Nelson,[138] which will increase the degree to which the basic charge recovers the FEU's fixed customer costs from those service areas.

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[133] Exhibit B-3, Application, p. 190.
[134] Exhibit B-15, BCUC IR 2.33.1 and 2.6.2.
[135] Exhibit B-9, BCUC IR 1.79.1 and Exhibit B-15, BCUC IR 2.33.1.
[136] Exhibit B-9, BCUC IR 1.79.1.
[137] Exhibit B-15, BCUC IR 2.33.1.
[138] Exhibit B-15, BCUC IR 2.39.3.

(b) Applying FEI's flat postage stamp rate structure to Fort Nelson will eliminate the existing declining block rate structures currently in place and will provide energy conservation pricing signals for those customers.[139]

126. Improvements to the efficiency of the rate design for FEI Amalco can be considered in future rate design proceedings.[140] The FEU submit that once the rates are postage stamped, it will be easier and more efficient to consider such changes.

127. The FEU therefore submit that its proposed postage stamp rates meet the principle of efficiency and represent an improvement over the existing rates in place for FEVI, FEW and FEFN.

4.7 Competitiveness

128. The rate design principle of Competitiveness means the consideration of other fuel alternatives and the changing market conditions in designing a rate.[141] The harmonized rates proposed for the Amalgamated Entity will have minimal impact on competitiveness of natural gas for the vast majority of customers currently served by FEI. On the other hand, the rates for FEVI and FEW will become more economic compared with alternative fuels.[142] The FEU expect that this increased competitiveness will help retain customers and provide further incentive for those using propane and heating oil to convert to natural gas.[143]

129. In addition, as stated in Exhibit B-12, BCRUCA IR 2.1.1:

> Postage stamp rates would provide a better market signal for decisions about which energy source (electricity or natural gas) for residential consumers to use in end-use applications that can be served by natural gas. All residential consumers will use electricity in their homes for purposes such as lights and appliances, so the question of gas versus electricity (or other energy sources such as geo-exchange systems) comes into play mainly for thermal end-

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[139] Exhibit B-9, BCUC IR 1.7.2.3.
[140] Exhibit B-15, BCUC IR 2.33.1.
[141] Exhibit B-3, Application, pp. 190 -191.
[142] Exhibit B-9, BCUC IR 1.7.2.3.
[143] Exhibit B-3, Application, p. 114; Exhibit B-15, BCUC IR 2.52.1.

> uses such as space heating and water heating. Since electricity rates in BC Hydro's service territory are postage stamped across the province, efficient decision making with regard to energy choices would be facilitated by having the same natural gas rates in place in the various parts of the FEU's service territories. Having postage stamp rates for both electricity and natural gas would mean that the analysis and value proposition on the choice of energy systems would be similar throughout the province, rather than having some areas such as FEI and FEFN with a stronger business case and other areas (FEVI and FEW) with a weaker one.[144]

130. The FEU submit that this will also aid BC Hydro in acquiring and deploying resources based on appropriate price signals. The FEU therefore submit that its proposed postage stamp rates are better aligned with the principle of competitiveness than the existing rates.

4.8 Recovery of the Cost of Service

131. The last rate design principle is recovery of the cost of service. The proposed interim postage stamp rates are sufficient to recover the Company's cost of providing service as they are based on the consolidated proposed revenue requirements for 2013 for the FEU, with necessary adjustments to account for amalgamation.[145] Moreover, before implementation, the rates will be adjusted to reflect the 2014 RRA and the outcome of the GCOC proceeding.

4.9 Conclusion on Rate Design Principles

132. In the FEU's submission, the proposed postage stamp rates are supported by a consideration of accepted rate design principles and better meet those principles than the existing rates.[146] In particular, postage stamp rates offer significant benefits in terms of fairness to customers, stability of rates, simplicity, and customer impact to FEVI and FEW customers. Other benefits include better alignment with the principles of efficiency and competitiveness, while the proposed rates continue to recover the cost of service. In the FEU's submission, the proposed postage stamp rates are just and reasonable and

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[144] Exhibit B-12, BCRUCA IR 2.1.1.
[145] Exhibit B-3, Application, p. 191.
[146] Exhibit B-12, BCRUCA IR 2.1.3.

should be approved by the Commission. The qualities of postage stamp rates are also a key benefit of the FEU's proposed amalgamation and make it beneficial in the public interest.

5.0 ADDITIONAL BENEFITS OF AMALGAMATION AND POSTAGE STAMP RATES

133. The FEU's proposal to amalgamate and implement postage stamp rates will result in other benefits, including cost efficiencies, the facilitation of access to service offerings and the furtherance of provincial energy policy. Each of these factors is addressed below.

5.1 Cost Efficiencies

134. A benefit of amalgamation and postage stamp rates is that it will result in regulatory, reporting and operational efficiencies. These benefits are due to:

(a) Regulatory Efficiencies: Consolidation of the separate entities, rate bases and service areas under one unified regulatory structure with common rates will reduce the regulatory requirements and streamline rate and compliance filings and other applications.[147]

(b) Legal Efficiencies: Minor costs savings will be realized due to the need for only one set of company records and to administer only one legal corporation.[148]

(c) Interest Savings: Interest expense savings of approximately $2.0 million are forecast to occur primarily as a result of the application of the FEI short-term debt rate to the FEVI and FEW short-term debt components of approximately $144.2 million.[149]

(d) Other Financial Efficiencies: FEI Amalco will experience savings of approximately $18,000/year for auditing requirements and $100,000/year for rating agency fees.[150]

135. Based on quantifiable benefits, the proposed amalgamation and postage stamp rate proposal has a positive NPV.[151] The assumptions made in the NPV analysis are

[147] Exhibit B-3, Application, p. 123.
[148] Exhibit B-3, Application, p. 123.
[149] Exhibit B-3, Application, p. 123.
[150] Exhibit B-3, Application, p. 124.

explained in response to BCUC IR 1.5.11 and each item is discussed in response to BCUC IR 2.2.2. Although the results should be viewed with caution, the FEU estimate benefits in the range of $901 thousand to $3,128 thousand, depending on the average short-term debt that would be applicable to the FEVI service area. The FEU estimate that it will take less than two years for the savings to exceed the one time amalgamation costs.[152]

136. Therefore, the proposed amalgamation and postage stamp rates will result in efficiencies and a reduction in the overall cost of service of FEI Amalco compared to the FEU.

5.2 Facilitation of Consistent Access to Service Offerings

137. Although all natural gas services could in theory be extended to areas outside of FEI Mainland through other regulatory approvals, the approval of amalgamation and postage stamp rates will facilitate an efficient extension of all services to all service areas, meaning that the services can be extended at less cost and in a timelier fashion.[153] The services that are currently not available to FEVI, FEW and FEFN that can be expanded upon amalgamation and postage stamp rates include: the Customer Choice Program; Transportation Service; CNG and LNG Fuelling Service; and Biomethane Service. Each of the four services is discussed below.

5.2.1 Customer Choice

138. Amalgamation and postage stamp rates will facilitate the efficient expansion of the Customer Choice Program to customers currently served by FEVI, FEW and FEFN, providing all customers served by the FEU with the option to purchase fixed rate commodity offerings from independent gas marketers. There is evidence that non-eligible customers are dissatisfied that the program is not an option in their service

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[151] Exhibit B-9, BCUC IR 1.5.11. See clarification in Exhibit B-15, response to BCUC IR 2.1.1 that this NPV analysis applies to amalgamation and postage stamp rates.

[152] Exhibit B-9, BCUC IR 1.5.11; Exhibit B-15, BCUC IR 2.1.2. A working excel spreadsheet supporting the NPV analysis was provided in Attachment 2.1 to Exhibit B-15 (as referred to in response to BCUC IR 2.2.1).

[153] Exhibit B-15, BCUC IR 2.54.1.

territory[154] and that marketers are interested in expanding the Customer Choice program to the remaining FEU service areas.[155]

139. If amalgamation is approved and postage stamp rates are implemented, the FEU are requesting an implementation date of November 1, 2014 for the expansion of Customer Choice beyond the Lower Mainland, Inland and Columbia service areas.[156] Customer education will be required to expand the Customer Choice Program to eligible customers of currently served by FEVI, FEW and Fort Nelson. The FEU propose to deal with the specifics of the Customer Education Plan for these customers in a separate regulatory filing for the Customer Choice Program following a decision on amalgamation.[157]

140. If amalgamation with postage stamp rates is not approved, the FEU submit that it may not be efficient to extend the Customer Choice Program. In the absence of postage stamp rates, the FEU would need to apply to the Commission for commodity unbundling and the adoption of an ESM Model and respective business rules for each of FEVI, FEW and FEFN based on their particular circumstances. As part of the unbundling process, the FEU would have to undergo the required system and bill print changes.[158] In addition, it would be necessary to create margin related deferral accounts for FEVI and FEFN to capture the variances between forecast and actual costs of the midstream and commodity separately. Only once commodity unbundling is completed and the system modifications executed, would the FEU be able to extend Customer Choice to FEVI, FEW and FEFN.[159]

141. The FEU therefore submit that amalgamation and postage stamp rates is beneficial in that it will allow the cost-effective expansion of the Customer Choice Program.

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[154] Exhibit B-3, Application, pp. 117 to 119.
[155] Exhibit B-9, BCUC IR 1.41.1.
[156] Exhibit B-3, Application, pp. 117 to 119. Also see Exhibit B-9, BCUC IR 1.42.1 and BCUC IR 1.42.3.
[157] Exhibit B-9, BCUC IR 1.43.1.
[158] See Exhibit B-9, BCUC IR 1.42.3
[159] Exhibit B-9, BCUC IR 1.39.1 and 1.42.1.

5.2.2 Transportation Service

142. Amalgamation and postage stamp rates would facilitate the efficient expansion of uniform transportation service based on FEI's existing rate schedules.[160] Transportation Service is a service whereby the transportation of the natural gas is completed through the distribution system, with the customer purchasing the commodity natural gas directly from the suppliers.[161] There are significant numbers of customers that would qualify for FEI's transportation services.[162]

143. The interest in transportation service in the FEVI, FEW and FEFN service areas may be assumed to be similar to the level of interest shown in FEI's existing transportation service offerings.[163] For example, approximately 20% of customers that are eligible for bundled service (i.e. commodity and transportation) under Rate Schedule 3 (Large Commercial) currently take transportation-only service under Rate Schedule 23 (Large Commercial Transportation). Similarly, almost 70% of eligible Rate Schedule 5 (General Firm Service) customers take service under Rate Schedule 25 (General Firm Transportation Service). The FEU anticipate that over time customers in other service areas will similarly elect to take transportation service if the FEU are able to provide uniform transportation service across all regions.

5.2.3 CNG and LNG Services

144. Under Section 12B of FEI's GT&Cs,[164] FEI installs and maintains CNG and LNG fuelling stations and dispenses CNG or LNG to customers at their sites. FEVI, FEW and Fort Nelson do not have the equivalent CNG and LNG service offering. Amalgamation and postage stamp rates would make FEI's GT&Cs 12B applicable to all regions, thereby facilitating the expansion of the service.[165]

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[160] Exhibit B-1, 1.44.5. In the absence of amalgamation and postage stamp rates, the requirements to introduce transportation service to FEVI, FEW and FEFN include unbundling of FEVI and FEFN rates, rate design (developing service offerings), approval of regulatory framework (e.g. approval of new rate classes), IT and billing improvements, and customers and gas marketer education.

[161] Exhibit B-3, Application, Section 6.5.2.

[162] Exhibit B-9, BCUC IR 1.44.2 and 1.44.3.

[163] Exhibit B-9, BCUC IR 1.44.1.

[164] Exhibit B-3, Application, section 6.5.3.

[165] Exhibit B-9, BCUC IR 1.40.1 and 1.40.4.

5.2.4 Biomethane Service

145. Amalgamation and the adoption of common rates will facilitate and accelerate the process of extending the Commission-approved Biomethane Service offering to FEVI, FEW and Fort Nelson customers. This will provide currently ineligible customers with an option to reduce their GHG emissions while continuing to receive natural gas service. It will also facilitate the expansion of the supply base for biomethane.[166]

146. In order to extend Biomethane service to the FEVI, FEW, and FEFN service regions under the current regulatory construct, it would require unbundling of the FEVI and FEFN's current rate structures, approvals of the regulatory framework (e.g. new rate schedules and cost recovery mechanisms), IT and billing system improvements and customer education.[167] While entity specific Biomethane programs could be implemented in any region, the FEI Biomethane Program could be expanded to FEVI, FEW, and FEFN more effectively and efficiently under an amalgamated model with a common rate structure.[168]

5.3 Provincial Energy Policy

147. The FEU submit that its proposed amalgamation and postage stamp rates are consistent with government energy policy.[169] In the following two subsections, amalgamation and postage stamp rates are considered from the perspective of energy policy related to natural gas as a transportation fuel and GHG emissions.

5.3.1 Natural Gas as a Transportation Fuel

148. One of the proposals in the Province's "Natural Gas Strategy: Fueling B.C.'s Economy for the Next Decade and Beyond,"[170] is to work "to promote natural gas as a transportation fuel". Since the release of the strategy document in February 2012, the

[166] Exhibit B-3, Application, Section 6.5.4.

[167] Exhibit B-9, BCUC IR 1.39.2.

[168] Exhibit B-9, BCUC IR 1.39.2.

[169] The FEU have provided an overview of provincial energy policy in section 4.1.4 (pp. 63 to 65) and Appendix G-0 of the Application. Appendices G-1 through G-9 provide supporting documents.

[170] Exhibit B-3-1, Appendix G-8, "Natural Gas Strategy: Fueling B.C.'s Economy for the Next Decade and Beyond", 3 February, 2012.

Greenhouse Gas Reduction (Clean Energy) Regulation[171] has come into force making incentives for natural gas vehicles and expenditures on CNG and LNG fueling stations prescribed undertakings under section 18 of the *Clean Energy Act.*

149. At present there is no CNG load in FEVI or FEW and the higher delivery rates are one important factor that makes it harder to develop the NGT market in these service territories.[172] The reduced rates in the FEVI and FEW service areas that would result from amalgamation and postage stamp rates would improve the economics of adopting natural gas as a transportation fuel in these service territories. This would be expected to help customers in these service areas make a decision to move to NGT by reducing one of the barriers that could be impeding their decision.[173]

5.3.2 GHG Policy

150. As outlined in section 4.14 of the Application and discussed in Appendices G-0, the province has implemented various policies targeting GHG reductions. Of particular importance to the Commission's jurisdiction are the "government energy objectives" listed in the *Clean Energy Act* and incorporated by reference into the *UCA*. Consistent with these objectives, the FEU expect that lower rates in the FEVI service area will encourage fuel switching from higher GHG emitting sources to natural gas consistent with the "government energy objectives."[174]

151. As discussed above, to the extent that lower rates in the FEVI and FEW service areas fosters natural gas as a transportation fuel, this should lead to reduced GHG emissions all else equal.[175] More affordable natural gas prices also have the potential to encourage customers to switch from higher GHG emitting energy resources, such as furnace oil and propane, in the FEVI service area where there still exists reliance on other fossil fuels for space heating and hot water. Using natural gas in place of other fossil fuels, all else

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[171] O.I.C. No. 295, dated May 14, 2012.
[172] Exhibit B-15, BCUC IR 2.54.2 and 2.55.1
[173] Exhibit B-9, BCUC IR 1.40.1 and 1.40.5 and Exhibit B-15, 2.47.3, 2.54.2 and 2.55.1.
[174] Exhibit B-3, Application, p. 128; Exhibit B-3-1, Appendix G-0.
[175] Exhibit B-3, Application, p. 128.

equal, will reduce the amount of GHG in BC.[176] Switching from heating oil to natural gas may occur since a home using heating oil will generally be appropriately configured to accommodate natural gas heating equipment.[177]

152. Fuel switching between natural gas and electricity, however, is not expected to be material.[178] Unlike homes fitted for heating oil, homes with electric base board heating are generally not configured for natural gas heating. The FEU have stressed that while postage stamp rates would reduce the delivery rate for natural gas in the FEVI and FEW service areas, operational price differential is only one of the determinants that inform customers' energy choices. Other factors include the higher capital cost to install the natural gas equipment and necessary in-house ducting, the system extension test and connection policies used, and consumer perceptions about the desirability of an energy source such as its green attributes. Even with the rate reductions from postage stamp rates, when the upfront capital cost is included in the analysis, natural gas continues to be challenged for FEVI and FEW relative to electricity.

153. Therefore, the FEU submit that postage stamp rates is aligned with government GHG policy as it will encourage fuel switching from higher GHG emitting resources to natural gas which will reduce GHG emissions all else equal.

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[176] Exhibit B-3, Application, p. 129.

[177] Exhibit B-15, BCUC IR 2.52.1.

[178] Exhibit B-3, Application, pp. 128-129; Exhibit B-9, BCUC IR 1.81.1, 1.81.2, 1.81.3 and 1.81.5; Exhibit B-15, BCUC IR 2.52.1. Also see Exhibit B-3-1, Appendix G-13: Residential User Preference Study and Appendix G-17: The "Gas Influencer Energy Preferences Study".

6.0 SERVICE AREA-SPECIFIC ISSUES

154. This section addresses issues related to amalgamation and postage stamp rates that are specific to a particular service area, including whether FEW should make a financial contribution, whether the FEW conversion costs should be excluded from postage stamp rates and whether postage stamp rates are appropriate for Fort Nelson.

6.1 FEW Contribution

155. A number of IRs raised the possibility of FEW making a financial contribution similar to FEVI's contribution through the RSDA. The rationale for postage stamp rates, however, applies whether or not any service area is able to provide an "up front" contribution. The primary rationale for harmonizing rates is that it is fair and equitable for all of the FEU's classes of natural gas customers to be charged the same rate for natural gas delivery service regardless of location. The disbursement of the RSDA has been proposed as a mitigation strategy, not as a condition which makes common rates appropriate.[179] In any case, there is no reasonable mechanism by which FEW could make an "up-front" contribution to the amalgamated entity in a way that is similar to FEVI's RSDA balance. The balance in the RSDA is a result of the unique situation in FEVI. As FEW rates have been reset each year to reflect the cost of service, the FEW has no revenue surplus to contribute towards amalgamation.[180]

6.2 Whistler Conversion Costs

156. The FEU submit that postage stamp rates should include the Whistler conversion costs. The conversion costs are no different than other project costs that occur throughout the FEU, the costs of which are spread across the customer base. Whistler's recent conversion from a propane to a natural gas system was approved in the public interest and successfully reduced rates for FEW customers. The fact that this conversion occurred recently should not change how the costs of this project should be recovered from customers under postage stamp rates.[181]

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[179] Exhibit B-9, BCUC IR 1.89.2.

[180] Exhibit B-9, BCUC IR 1.89.2; Exhibit B-15, BCUC IR 2.10.2.

[181] Exhibit B-9, BCUC IR 1.78.2 and BCUC IR 1.78.2.1.

157. Under postage stamp rates, all customers pay for the impact of localized projects. An example is the current Kootenay River Crossing (Shoreacres) project. Although constructed to serve the approximately 5,200 customers located in the City of Nelson and its surrounding area, the project costs will be spread across the entire FEI Mainland customer base.[182] Another example is FortisBC Inc.'s Big White Supply Project built to serve Big White Village. As discussed in Section 3 above, the Commission concluded that the costs of the Big White Supply Project should be rolled into rates rather than being charged to the community of Big White in particular. The Commission noted in the Decision that this treatment was consistent with its approval of other project costs, including an electric transmission project to serve Whistler.[183]

158. This postage stamp treatment has also been applied in the past in relation to customer conversions. The conversion costs that FEI incurred for interior municipalities, such as Nelson, were rolled into rates with the consolidation of the Lower Mainland, Inland and Columbia service areas.[184] A natural gas conversion project undertaken in 1991 in the Squamish area was later integrated into FEI. In addition, the FEU have a long-standing program offering incentives to customers to switch from fuel oil to natural gas, in which the incentives payments are recovered in rates for all customers.[185]

159. The FEU therefore submit that, consistent with the Commission's treatment of other project and conversion costs, the Whistler conversion costs should be included in the proposed postage stamp rates.

6.3 Application of Postage Stamp Rates to Fort Nelson is Reasonable

160. The FEU have requested that postage stamp rates be extended to Fort Nelson. The FEU have made it clear, however, that they would not consider the exclusion of Fort Nelson from postage stamp rates as a barrier to proceeding with amalgamation and

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[182] Exhibit B-3, Application, p. 76.

[183] BCUC Order G-87-07, dated August 7, 2007, Appendix A, p. 15 of 18, at Tab 2 of the FEU's Book of Authorities.

[184] Exhibit B-15, BCUC IR 2.38.1.1.

[185] Exhibit B-9, BCUC IR 1.77.1.1.

implementation of postage stamp rates over all of the other service areas of the FEU.[186] The exclusion of Fort Nelson would have no material impact on other customers. The FEU therefore submit that if the Commission ultimately concludes that it is inappropriate to apply postage stamp rates to Fort Nelson at this time, that this should not impact approval of postage stamp rates to the other service areas.

161. The FEU submit that there are essentially three options for Fort Nelson going forward: (1) the status quo, with Fort Nelson continuing as a separate rate base; (2) postage stamp delivery and commodity rates with regional midstream rates; and (3) postage stamp delivery, midstream and commodity rates. While the FEU are willing to proceed with of any of these three options, for the reasons described below, the FEU submit that full postage stamp rates are a reasonable option for Fort Nelson customers.

6.3.1 Fort Nelson is Vulnerable to Rate Instability on a Stand-Alone Basis

162. While Fort Nelson residents have historically enjoyed lower rates relative to FEI Mainland, FEVI and FEW customers, as a separate service area and rate base with a relatively small and less diverse customer base Fort Nelson is highly vulnerable to rate increases. In particular, over the next 15 years rate impacts may be expected from the loss of industrial load and capital expenditures. The need for rate rebalancing is an additional factor that can be expected to put upward pressure on Fort Nelson residential rates in particular.[187] These pressures are discussed below

163. First, Fort Nelson faces challenges of a less diverse customer base. The top ten highest consuming FEFN customers consume 17% of total throughput and account for 11% of total revenue. In comparison, FEI has a more balanced ratio, with the top 10 consuming customers accounting for only 6 percent of total throughput and less than 1 percent of total revenues.[188] A heavy reliance on a relatively small number of customers to generate significant throughput is compounded when these customers are part of the same industry. Thus, the impact of Canfor closing its two plants in the Fort Nelson region was

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[186] Exhibit B-9, BCUC IR 1.2.3.

[187] Exhibit B-9, BCUC IR 1.99.1.

[188] Exhibit B-3, Application, pp. 76-77.

a forecast revenue deficiency of $258 thousand, or a 25% increase to delivery rates. Since that time, the two plants have been consuming natural gas for space heating only and it is anticipated that one of these two contracts will terminate in 2012, resulting in a forecasted decrease of 13.9 TJs, or 2.2% of total demand volumes. This decrease in system throughput will place upward pressure on rates for existing and potential Fort Nelson customers.[189]

164. With approximately 2,400 customers, Fort Nelson's small customer base leaves it vulnerable to rate increases from capital investments.[190] The Muskwa River Crossing upgrade in Fort Nelson at a forecast cost of $3.1 million provides an example of how capital expenditures can impact rates for Fort Nelson. The cost of service associated with the Muskwa River Crossing is approximately $260 thousand in 2013, which all else equal results in an increase to the delivery rate of approximately 13.7 percent, or roughly a $54 increase to an average residential customer's annual bill.[191] The vulnerability of Fort Nelson is real as maintenance capital expenditures in Fort Nelson are expected to increase and Fort Nelson may experience additional capital expenditures under the Long-Term Sustainment Plan.[192]

165. In addition to the challenges discussed above, the status quo for Fort Nelson is likely to change due to the need to rebalance rates. Aside from Canfor which is served under a transportation rate schedule, Fort Nelson customers are served under three rate schedules, one residential (Rate Schedule 1) and two commercial (Rate Schedules 2.1 and 2.2). The current revenue-to-cost ratios show that there is a need for rebalancing, with the residential customers having a ratio of 81% and the commercial rate schedules having ratios of 116% and 129%.[193]

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[189] Exhibit B-3, Application, pp. 77 to 78.

[190] Exhibit B-3, Application, pp. 35 to 36.

[191] Exhibit B-3, Application, pp. 75 to 76. The costs of the Muskwa River project are potentially greater depending on whether approval can be obtained from the Federal government for the current solution. Based on current estimates an alternative solution will likely be higher in cost, and increase the rate impact. Exhibit B-9, BCUC IR 1.147.2; Exhibit C2-3, Fort Nelson and District Chamber of Commerce Submission, Appendix A, Email from Bob Gibney dated March 28, 2012.

[192] Exhibit B-9, BCUC IR 1.100.1, 1.100.1.1 and 1.100.1.2.

[193] Exhibit B-3, Application, pp. 36 to 37.

166. Based on estimates of the potential impact of these factors, residential customers in Fort Nelson could see significant increases in rates over the coming 15 year period under the status quo.[194] The following list demonstrates the potential impact on residential rates of each of these items, taken in isolation:[195]

- With both Canfor customers shut down, the approximate average burner tip impact to residential rates will be an increase of 3.3%.
- Forecasted maintenance capital expenditures are expected to result in an approximate average burner tip increase of 15% over a 15 year period.
- Rebalancing rates to achieve a revenue to cost ratio between 90% and 110% in 2014 would result in an approximate burner tip increase of approximately 21% for residential customers.

167. For these reasons, Fort Nelson is vulnerable to rate increases in the future and the status quo is expected to change due to the need for rate rebalancing.

6.3.2 Postage Stamp Rates will Provide Rate Stability

168. Fort Nelson will benefit from more stable rates under postage stamp rates. Postage stamp rates will address Fort Nelson's vulnerability to rate pressure due to its small and less diverse customer base described above. Under postage stamp rates all capital expenditures will be spread amongst customers of the amalgamated entity smoothing out the impact to all customers.

169. In its intervenor evidence, the Fort Nelson and District Chamber of Commerce has suggested that rate stability will not be a benefit because Fort Nelson will share in the cost of capital projects throughout the FEU.[196] Capital costs are only one factor affecting rates, with other factors including the number of customers and loss of load. It is true, however, that under the FEU’s proposed postage stamp rate structure, costs of capital projects will be shared across all customers of the amalgamated entity. Just as Fort Nelson would benefit from spreading localized capital projects across the entire customer base, other customers similarly benefit from the spreading of costs. Over time, the costs of these investments are expected to even out across the customer base while at the same

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[194] Exhibit B-15, BCUC IR 2.48.1.
[195] Exhibit B-9, BCUC IR 1.99.1.
[196] Exhibit C2-3, p. 2.

time protecting all customers from swings in rates due to the timing of capital projects that happen to affect their local area.[197]

170. When under postage stamp rates, Fort Nelson will also receive any benefits of capital projects. In its intervenor submission, Fort Nelson questions where the capital for the Kingsvale to Oliver Reinforcement project is coming from.[198] While the capital would indeed be spread across the customer base, the benefits from the project would also be. As indicated in the news release attached as Appendix B to the Fort Nelson and District Chamber of Commerce's submission and the Commission's recent Decision approving development funding for the project,[199] the Kingsvale to Oliver Reinforcement project is being developed in part to generate revenues for customers and is expected to offset increases to natural gas rates over time. If Fort Nelson is not under postage stamp rates, it will not share in these benefits.

171. Even capital assets that are remote geographically to Fort Nelson can provide important benefits. The benefits of the Tilbury and Mt. Hayes on-system storage resources, for instance, can provide benefits to Fort Nelson if, for instance, the Fort Nelson gas plant had an outage.[200] The use of the LNG facilities in this manner exemplifies how FEI's total pool of resources is used collectively as required in order to manage the total daily load for FEI, including Fort Nelson.[201]

172. In the FEU's submission, postage stamp rates will provide a benefit to Fort Nelson customers in the form of more stable rates and may help to mitigate some of the key rate increase drivers for Fort Nelson described above. While it is true that Fort Nelson will see rate increases driven by capital projects across FEI Amalco, these increases can be expected to be more smooth than if Fort Nelson were to absorb the cost of local capital investments alone.

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[197] Exhibit B-3, Application, section 4.4; Exhibit B-3-1, Appendix D-1, EES Consulting Report, p. 7.
[198] Exhibit C2-3, p. 2.
[199] Order No. G-101-12, dated July 23, 2012, Appendix A, p. 7 of 9.
[200] Exhibit B-9, BCUC IR 1.47.2.
[201] Exhibit B-9, BCUC IR 1.47.2.1.

6.3.3 Postage Stamp Rates Reflect the Integration of the FEU

173. Full postage stamp rates are the only option that fully reflects the common ownership and management of the FEU and the physical and operational integration of the FEU's systems. The FEU manage and operate on a fully integrated basis as a single system and have common management control and decision making systems, common distribution, transmission, and business support operations, and optimize the supply of natural gas based on managing the needs of a portfolio of resources that minimizes costs for all customers.[202]

174. Fort Nelson has benefited and continues to benefit from this integration today. Operationally, for instance, Fort Nelson benefits from the cost structure of FEI. These benefits include more stable commodity costs, lower cost of capital, reduced cost of materials and supplies and more efficient operating and maintenance cost structures. FEI is a large buyer of natural gas and, due to its relationships with gas suppliers, FEI is able to contract for cost effective and reliable supply for Fort Nelson customers. In addition to commodity-related benefits, Fort Nelson benefits from FEI's access to low cost capital funding. On its own, Fort Nelson would likely not be able to obtain access to funds at the favourable rates and terms that FEI is able to obtain as a larger utility. The purchasing power of a larger company also leads to reduced costs of pipe and other materials and supplies. Another benefit afforded to Fort Nelson is access to the necessary resources, expertise and training in all areas affecting gas distribution utilities, such as the engineering department, human resources personnel, a comprehensive IT system, and regulatory. In short, Fort Nelson has historically enjoyed many of the benefits that typically only accrue to a larger gas utility.[203]

175. It may be argued that Fort Nelson's geographical location, in terms of proximity to sources of natural gas supply and distance from other parts of the FEU's systems make it unreasonable to implement postage stamp rates. This is incorrect. FEFN is directly connected to the FEU's facilities through the lateral connection to Westcoast Energy

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[202] Exhibit B-15, BCUC IR 2.11.2.
[203] Exhibit B-3, Application, p. 36.

Inc.'s system, and FEFN benefits from being part of the overall midstream portfolio. As stated in response to BCUC IR 1.47.1:

> To meet the daily load requirements of Fort Nelson, FEI uses commodity supply and third party transportation services. Gas supply is sourced by FEI from a producer at the outlet of the Fort Nelson gas processing plant for delivery to customers in Fort Nelson. FEI also contracts for third party transportation capacity from Westcoast Energy Inc. ("Westcoast") on its T-North system in order to move gas supply each day from the plant's outlet for delivery to the town.
>
> FEI contracts commodity supply for Fort Nelson with a producer who is one of the qualified counterparties that FEI uses for its overall gas supply requirements. Because of the strong and long term supply relationship with this producer, FEI is able to contract separately for firm term supply to Fort Nelson on favourable and flexible terms for its daily requirements. This relationship enables secure, flexible, and cost effective supply to Fort Nelson's customers.
>
> From an operational perspective, FEI schedules the required amount of gas supply with the supplier and the pipeline each day based on forecast load requirements for the next day. FEI's unique arrangement with the producer, and the relatively small volume compared to FEI's overall supply portfolio, enables FEI to take only what it requires based on the next day's load forecast for Fort Nelson rather than taking 100% of the contracted quantity each day. Most firm term gas supply contracts require the seller to deliver and the purchaser to take the full quantity of supply that is contracted under the terms of a deal on a daily basis.
>
> Any excess or shortfall in gas supply based on the town's demand for the actual gas day is managed via a balancing agreement that FEI has with Westcoast that governs imbalances related to the total T-North transportation capacity FEI holds in its overall portfolio. FEI and Westcoast then settle the cumulative imbalance due to over-or-under deliveries over the course of the month in order to manage imbalances on a timely basis.

176. As reflected in the above response, FEI already optimizes its portfolio by combining the Fort Nelson requirements into its total pool of resources. The FEU operate the entire system including assets such as the Mt. Hayes and Tilbury LNG facilities to serve all customers, including those in Fort Nelson. The FEU submit that postage stamp rates will

more fairly reflect the integrated nature of the utility, its operations and the system from which FEFN currently benefits.

177. In particular, the integration of FEI and FEFN and the system in general indicates that a regional midstream rate is less appropriate than a postage stamp rate. The total midstream costs allocated to FEFN customers under the postage stamp midstream option are approximately $760 thousand.[204] The table below provides the composition of the total FEFN midstream costs to be recovered, by rate class, indicating that the postage stamp midstream rates would reflect the load factor differences between rate classes:[205]

Fort Nelson Midstream Costs, By Rate Class, Under Postage Stamp Rates Option

	Rate 1	Rate 2	Rate 3	Total
Midstream Volumes *(TJ)*	274.3	193.3	119.4	587.0
Postage Stamp Midstream Charge *($/GJ)*	$ 1.384	$ 1.316	$ 1.055	
Total Allocated Midstream Costs *($000)*	$ 379.7	$ 254.3	$ 126.1	**$ 760.1**

178. As shown in the table above, the midstream costs are allocated to the various customer rate classes on a load factor adjusted volumetric basis, which appropriately reflects the demand each customer class places on the midstream resources required to meet their peak demand.[206]

179. The postage stamp allocation more appropriately reflects the value provided to FEFN customers than the current midstream allocation.[207] Postage stamping of the midstream rate would recognize that FEI optimizes its pool of resources as a single portfolio on a

[204] The gas cost recovery charge component of Fort Nelson's rates currently includes an allocation of certain costs of the overall portfolio, including an allocation of Aitken Creek storage costs from the FEI portfolio, charges for transportation service provided by Westcoast Energy Inc. to move gas from the Fort Nelson gas processing plant outlet to the Town of Fort Nelson, and the costs related to Unaccounted For ("UAF") gas within the Fort Nelson system. Based on the 2013 test year gas cost forecast, the annual midstream costs allocated to Fort Nelson are approximately $162 thousand, which would equate to an average midstream cost recovery rate of approximately $0.276 per GJ on a forecast sales volume of 586 TJ. (Exhibit B-9, BCUC IR 1.143.1.1.)

[205] Exhibit B-15, BCUC IR 2.72.1.

[206] Exhibit B-15, BCUC IR 2.72.2.

[207] Exhibit B-15, BCUC IR 2.72.2.

total regional level that includes FEFN.[208] Although the adoption of postage stamp midstream rates by Fort Nelson will not in itself result in additional benefits to the overall gas portfolio, it does more appropriately recognize the benefits that Fort Nelson customers already receive by being part of the overall FEI portfolio and contracting activities.[209]

180. As more fully discussed in section 4 above, the postage stamping of rates in Fort Nelson would be more consistent with the existing utility rates in place throughout the Province, including the postage stamp electric rates of BC Hydro which extend to Fort Nelson. FEI Mainland's postage stamp rates already extend to approximately 850,000 natural gas customers in many different communities across the Province, including northern communities such as Chetwynd and Hudson's Hope.[210] FEI Mainland's postage stamp rates also extend to Revelstoke, which is less physically interconnected than Fort Nelson.[211] Mr. Saleba agrees, stating:[212]

> Fort Nelson customers would see the biggest impact due to the consolidation of rates. At one time these customers were separated both legally and for ratemaking treatment due to their unique location on the system. However, this regional differentiation was not adopted for other customers in the FEI system that might have a higher or lower than average cost of service. It is difficult to justify a continuation of regional rates for this specific area when other areas are not given a similar separation of costs on a regional basis. However, we believe it is appropriate to temper the rate impacts by using a phase-in approach.

181. Furthermore, the expert evidence of Mr. Saleba is that Fort Nelson is not sufficiently unique to justify a separate regional rate.[213] In the FEU's submission, while Fort Nelson was historically a separate utility, this should not be a driver of rate design today. Today, postage stamp rates are the most consistent approach and are in accordance with accepted rate design principles.

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[208] Exhibit B-15, BCUC IR 2.72.3.
[209] Exhibit B-9, BCUC IR 1.47.6 and 1.47.8.
[210] Exhibit B-15, Attachment 1.4.
[211] Exhibit B-15, Attachment 1.4.
[212] Exhibit B-3-1, Appendix D-1, EES Consulting, "Natural Gas Cost of Service Review," p. 7.
[213] Exhibit B-15, BCUC IR 2.6.4.

6.3.4 Conclusion on Fort Nelson

182. For the reasons discussed above as well as in the more general discussion of postage stamp rates in sections 3, 4 and 5, the FEU submit that postage stamping of the delivery, midstream and commodity rates for Fort Nelson is just and reasonable. The FEU recognize the significant rate impact to Fort Nelson customers due to the harmonizing rates and, as discussed above, have accordingly proposed a 15 year phase-in period. The FEU submit that this extended phase-in period would substantially mitigate the rate impact and smoothly transition Fort Nelson to postage stamp rates.

7.0 ALTERNATIVE AMALGAMATION SCENARIOS

183. In section 5 of the Application, the FEU analyzed various possible amalgamation and rate design options. Alternatives were also considered further in the two rounds of information requests. While the FEU are confident they can proceed with the proposed amalgamation or sufficiently similar options, the FEU would have to study any other option to determine if it could proceed. In particular, as explained on page 132 in the Application, the FEU must consider the fact that amalgamation should not be prejudicial to bondholders:

> FEI's Trust Indentures permit amalgamation of FEI with one or more other companies if certain terms and conditions are complied with. For instance, FEI's Trust Indentures contain a "Successor Company" provision which essentially requires that FEI not enter into any transaction whereby all or substantially all of its undertaking would become the property of another company – called the successor company – unless, among other things, the successor company executes an indenture that is satisfactory to the Trustee to evidence the assumption by the successor company of the due and punctual payment of all the debentures under the trust indenture and the agreement of the successor company to observe and perform all of the obligations of the Company under the trust indenture. Additionally, the transaction shall, to the satisfaction of the Trustee and in the opinion of counsel, be upon such terms as substantially to preserve and not to impair any of the rights and powers of the Trustee or the holders of the debentures under the trust indenture upon such terms as are in no way prejudicial to the holders.

184. If there are adverse rating agency impacts from any amalgamation scenario, the FEU would have to consider whether it may still be able to proceed with amalgamation. To be clear, the credit rating agencies have indicated that amalgamation with postage stamp rates will likely be credit neutral. The FEU are not aware of the credit rating agencies view of other options, but do not expect that the credit agencies' conclusions on credit neutrality would change under options sufficiently similar to FEU's proposal.

185. Two options that the FEU have indicated would be sufficiently similar to its proposal include the options of excluding Fort Nelson from postage stamp rates or implementing

regional midstream rates.[214] These options would not materially change the impact to the FEU's approximately 950,000 customers outside of Fort Nelson compared to the FEU's proposal.[215] The FEU therefore believe that both of these options would result in net benefits for customers and are feasible options.[216]

186. Another option considered feasible is the amalgamation of only FEI and FEVI. As FEW and FEFN have approximately 2,600 and 2,400 customers respectively, excluding FEW and FEFN would result in no material change to the remaining customers of the FEU. However, under this option the rate disparity and long-term rate instability would remain for FEW and FEFN customers. While Fort Nelson has been discussed in detail above, the extension of postage stamp rates would result in significant benefits to FEW customers. As there is no material benefit to other customers from excluding FEW and a material benefit to FEW customers from being included, the FEU submit that it is therefore more appropriate to include FEW in the amalgamated entity with postage stamp rates.[217]

187. The option of amalgamating only FEVI and FEW, however, is not feasible. While it would not impact FEI customers, this option offers no material benefits and there is no net benefit to customers.[218] The FEU would not proceed with this amalgamation scenario.[219]

188. Amalgamation with regional rate structures so that there would effectively be no change in rates is also not an acceptable option to the FEU.[220] This option would achieve amalgamation, but not any of the benefits associated with postage stamp rates. The rate discrepancies that currently exist based on historical acquisitions would continue and the smaller service areas of FEVI, FEW and FEFN would continue to be challenged by long-term rate instability.

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[214] Exhibit B-9, BCUC IR 1.2.3.
[215] Exhibit B-9, BCUC IR 1.2.1.
[216] Exhibit B-15, BCUC IR 2.3.1.
[217] Exhibit B-15, BCUC IR 2.2.1.1, 2.3.1 and 2.3.1.1.
[218] Exhibit B-15, BCUC IR 2.2.1.1 and 2.3.1.
[219] Exhibit B-15, BCUC IR 2.3.2.
[220] Exhibit B-15, BCUC IR 2.3.3.

189. The primary reason for pursuing amalgamation with regional rates would presumably be to achieve any remaining cost-efficiencies available due to the common ownership of the utilities. With regional rates, however, most of the efficiencies discussed in the Application could not be achieved.[221] While some legal efficiencies could occur, regulatory efficiencies could not be achieved, financial efficiencies would be limited, and interest savings would be less certain, dependent on the credit rating impact.[222] If there are adverse rating agency impacts, the FEU may not be able to proceed with amalgamation with regional rates.[223]

190. Given the potential negative consequences of amalgamation with regional rates, and a lack of any material benefit, the FEU would therefore not proceed with the option of amalgamation and regional rates reflecting existing rate structures.

[221] Exhibit B-15, BCUC IR 2.30.1.2.
[222] Exhibit B-9, BCUC IR 1.2.1 and 1.5.12; Exhibit B-15, BCUC IR 2.1.2, 2.3.3 and 2.30.1.2.
[223] Exhibit B-15, BCUC IR 2.3.3.

8.0 IMPLEMENTATION AND OPERATION

191. This section of the Argument will address issues related to the implementation of the proposed amalgamation and postage stamp rates, including the GT&Cs, MX Test, combined natural gas procurement portfolio and data retention for FEI Amalco.

8.1 General Terms and Conditions

192. The FEU are seeking approval of a common set of GT&Cs and rate schedules for FEI Amalco. The proposed GT&Cs and rate schedules have been updated and filed as Attachment 73.1 to Exhibit B-15.[224] The common set of GT&Cs, similar to those of the current FEI service area, will harmonize tariffs, rate design principles and rate classifications across all areas served by FEI Amalco. In addition to amendments to harmonize the GT&Cs and rate schedules, the FEU have also proposed some house keeping amendments.[225]

193. Blacklined GT&Cs compared to FEI's current GT&Cs are provided in Appendix B-3 of the Application. Blacklined GT&Cs compared to FEVI, FEW and FEFN GT&Cs are provided in Exhibit B-15, Attachment 16.1 (electronic only).

194. As there are many minor changes to the GT&Cs and rate schedules, the FEU do not propose to address each change in this submission. The FEU have provided the following to explain the proposed changes to the GT&Cs and rate schedules:[226]

(a) In the Application and in the responses to information requests the FEU provided explanations for the changes to FEI's GT&Cs to reflect the proposed FEI Amalco's GT&Cs that are not simply in the nature of housekeeping. Some of the housekeeping items are also explained in the responses to information requests.[227]

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[224] Please see Exhibit B-15, BCUC IR 2.74.1 for a list of the corrections that were made to the proposed GT&Cs and Rate schedules following the first round of information requests.

[225] Exhibit B-3, Application, pp. 134-136.

[226] Exhibit B-15, BCUC IR 2.16.2.

[227] Exhibit B-9, BCUC IR 1.118.1, BCUC IR 1.122.1, BCUC IR 1.123.1, BCUC IR 1.125.1, BCUC IR 1.114.1, BCUC 1.113 series, and BCUC IR 1.111.1.

(b) In Exhibit B-15, BCUC IR 2.16.2, the FEU have provided a comprehensive table with an explanation of the impact of the changes in GT&Cs and rate schedules for FEVI, FEW and FEFN residential, commercial and industrial customers.

(c) The FEU have provided descriptions of all the rate classes in Section 3 of the Application and provided an analysis of how the FEVI, FEW and FEFN rate classes map onto the FEI rate classes in Section 9 of the Application.

(d) The rate impact for the changes to each service area as a whole is addressed in Appendices J-3 and J-4 of the Application.

195. Based on the evidence referred to above, the FEU submit that the proposed changes to the GT&Cs and rate schedules are just and reasonable and should be approved.

8.2 Main Extension Test

196. As described in section 7.4.2.3 of the Application, the FEU are proposing to continue FEI and FEVI's approved MX Test for FEI Amalco with the use of amalgamated inputs which properly reflect the implementation of amalgamation and postage stamp rates.

197. As explained in the Application, the particulars of the FEU's proposal for the MX Test are as follows:[228]

- FEI Amalco will continue with the Profitability Index methodology as approved by the Commission under Order No. G-152-07 for FEI and FEVI whereby an individual PI threshold of 0.8 and an aggregate PI of 1.1 are to be used. (The PI is the ratio of the discounted present value of all forecast net cash inflows over twenty years divided by the discounted present value of the capital costs of attaching customers in the first five years of the main extension.) Under the proposal, FEW will be adopting the FEI and FEVI PI threshold to bring all service areas across the areas served by the FEU into alignment.
- FEI Amalco will use one set of PI formula inputs reflecting the amalgamated entity as a whole. The result of the use of these inputs is that FEVI and FEW customers' PI values would decrease as a result of amalgamation, suggesting that under amalgamation, more FEVI and FEW customers will be required to provide a CIAC to achieve the required PI thresholds. In contrast, FEI customers' PI values would increase as a result of amalgamation, suggesting that fewer FEI customers will be required to provide a CIAC to achieve the required thresholds.

[228] Exhibit B-3, Application, pp. 137-141.

198. The FEU submit that the continuation of the FEI and FEVI approved MX test for the Amalgamated Entity reflects established main extension policy and is just and reasonable.

8.2.1 Jurisdiction to Approve Main Extension Test

199. Similar to past applications and approvals, the FEU are requesting approval of the MX test, including its reporting requirements, pursuant to the Commission's rate making powers in section 58 to 61 of the *UCA*.[229] A "rate" is defined in section 1 of the *UCA* to include:

> (a) a general, individual or joint rate, fare, toll, charge, rental or other compensation of a public utility,
>
> (b) a rule, practice, measurement, classification or contract of a public utility or corporation relating to a rate, and
>
> (c) a schedule or tariff respecting a rate.

200. The MX Test as set out in section 12 of FEI and FEVI's GT&Cs governs the contribution in aid of construction that a customer must provide, being a form of "compensation of a public utility". The reporting requirements and methodologies which are part of the MX Test are a "rule…practice…relating to a rate." In this respect, they are no different than other sections of FEI and FEVI's GT&Cs approved by the Commission. While the FEU consider the reporting requirements to be part of the rate, the Commission also has jurisdiction to require reporting pursuant to section 43 of the *UCA*. In previous Commission Decisions, the Commission has in fact directed FEI and FEVI to report on main extensions.[230] Section 72(2) of the *UCA* makes it clear that the Commission has jurisdiction to hear and determine anything to which its jurisdiction extends, which includes the approval of rate methodologies and reporting requirements.

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[229] Exhibit B-9, BCUC IR 1.28.1.

[230] E.g., Order G-152-07 and accompanying Decision, System Extension and Customer Connection Policies Review, dated December 6, 2007, on page 37 (at Tab 10 of the FEU's Book of Authorities).

8.2.2 Main Extension Reporting

201. The FEU submit that its proposed approach to MX Test reporting is reasonable and should be approved. The Companies are proposing to continue the existing approach to annual MX reporting until the 2014 MX Report is filed. From 2014 onwards, pre-amalgamation main extensions will continue to be reported on in the same manner as is currently done by the pre-amalgamation individual utilities, whereas post-amalgamation main extensions will be reported on as a single entity. This means that the 2009-2013 main extensions will continue to be reported on for the first five years of their existence segmented by FEI and FEVI random samples and top 5 mains and using the original MX Test inputs. Mains from 2014 and later will be reported on by the FEI Amalco entity using the new MX Test inputs for the amalgamated entity. A more detailed description of what the 2014 MX Report would contain is provided in Exhibit B-9, BCUC IR 1.29.1.[231]

202. The FEU currently provide MX reporting to the Commission at a utility level (i.e. FEI and FEVI)[232] and the FEU are therefore proposing to continue to report at the utility level for the amalgamated entity. The proposed FEI Amalco MX reporting will continue to provide the Commission with appliance use inputs and geo-code pricing segmented geographically.[233] All other data presented in the MX Report relating to post-amalgamation main extensions will be reported on an amalgamated basis.

203. The FEU submit that its proposed utility level approach to MX reporting is appropriate, consistent with the previously approved MX Test and should continue post-amalgamation. Requirements to provide more region-specific information would be inconsistent with the principle of postage stamp rates and would require extra cost and effort, reducing the efficiencies gained from amalgamation and postage stamp rates.[234] The FEU therefore submit that such regional reporting would not be cost effective, serves no reasonable purpose and should not be ordered by the Commission.

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[231] Exhibit B-9, BCUC IR 1.29.1, 1.32.3.
[232] Exhibit B-15, BCUC IR 2.62.3.
[233] Exhibit B-9, BCUC IR 1.34.1.
[234] Exhibit B-15, BCUC IR 2.62.3.

8.3 Combined Natural Gas Procurement Portfolio

204. Consistent with amalgamation and postage stamp rates, the FEU are seeking approval for a combined natural gas procurement portfolio. Combining the current separate gas procurement portfolios and the associated policies and rate constructs as part of the amalgamation will provide benefits to customers, including greater operational effectiveness, expanded contracting flexibility, and regulatory efficiency. While the FEU anticipate a number of benefits from the creation of a single combined portfolio, this change is not expected to provide immediate cost savings in any material way. This change however, will allow FEI Amalco to optimize the portfolio so that cost savings can be realized over the longer term.[235] In the FEU's submission, no material issues were raised in respect to this proposal.

8.4 Retention of Regional Data

205. The FEU submit that the appropriate amount of regional data for the purposes of determining rates will be maintained post-amalgamation or could otherwise be developed upon request. The FEU have described the regional data that they will continue to maintain following amalgamation, the regional data that they will be able to determine, and other regional costs that they could derive through the development of cost allocation methodologies.[236]

206. Certain data that is required to calculate the revenue requirements by service area will no longer be readily available once amalgamation proceeds and only one legal entity exists. For example, it would not be possible to have a separate lead/lag study performed when there is no legal entity data available as an input.[237] In order to provide the same level of regional data that exists today, FEI Amalco would need to develop allocation methodologies to regionalize costs. This would be accomplished in a manner similar to how FEFN's rate base and cost of service is determined today.[238] The FEU do not expect that there will be an ongoing need to see regional data after the proposed amalgamation

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[235] Exhibit B-3, section 7.4.3.
[236] Exhibit B-15, BCUC IR 2.31.1.
[237] Exhibit B-15, BCUC IR 2.3.5.
[238] Exhibit B-15, BCUC IR 2.3.5.

and postage stamp rates are approved, but that such data could be provided upon request of the Commission.[239]

[239] Exhibit B-15, BCUC IR 2.3.5.

9.0 COST OF SERVICE ISSUES

207. The FEU's proposed interim postage stamp rates for the amalgamated entity are based on the consolidated cost of service for the FEU proposed for 2013 in the 2012-2013 RRA, with adjustments for amalgamation as described in section 8 of the Application. If amalgamation is approved, the FEU will update the cost of service for the amalgamated entity for 2014 in a revenue requirement application filed in 2013.[240]

208. In the following sections, the FEU address issues related to the cost of service, including the FEU's proposed new deferral accounts, the suggestion that the shareholder make a financial contribution, and Mr. Robinson's positions that the rate base of FEVI be reduced and that the cost of service is uncertain.

9.1 Deferral Accounts

209. The FEU's deferral account requests are as follows:

(a) The FEU are requesting the consolidation of the existing margin related accounts upon amalgamation into one set of margin-related accounts (CCRA, MCRA and RSAM) as of January 1, 2014. These accounts will each follow the same treatment as is currently approved through Commission Order G-44-12. The same principles and mechanisms will be extended from the individual entity accounts to the amalgamated accounts. Details on how each of these margin-related accounts would function post amalgamation are provided in Exhibit B-15, response to BCUC IR 2.76.1.[241]

(b) The FEU are requesting approval of the disposition of the RSDA in order to implement the proposed phase-in of postage stamp rates.[242]

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[240] Exhibit B-3, Application, p. 14.

[241] Exhibit B-3, Application, p. 156-157; Exhibit B-15, BCUC IR 2.76.1.

[242] Exhibit B-3, Application, p. 155 and 157, as updated by Exhibit B-15, BCUC IR 2.70.2 and 2.70.4 to include interest on the RSDA.

(c) The FEU are requesting approval of 4 new deferral accounts, as shown in the table below.[243] Details on how each of these accounts would function post amalgamation are provided in Exhibit B-15, BCUC IR 2.77.1.

Type of Change	Account	Reference/Description
New Account	Amalgamation Costs Deferral Account	To capture the costs of amalgamation in a deferral account for future recovery from customers with amortization period TBD.
	Company Use and Unaccounted For Gas Cost Variance Account	Capture the variance in the company use and unaccounted for gas costs between the actual costs incurred and the forecast costs embedded in the FEI Amalco O&M expense, variances will be accumulated and amortized in rates over a one year period commencing in 2015.
	Amalgamation and Rate Design Application Costs	Non-rate base account, attracting interest to capture costs of this application, for future recovery from customers with amortization period TBD.
	Fort Nelson Phase-In Rate Rider Account	Non-rate base account, attracting interest.[244] Rider mechanism as discussed in Section 8.2.1.2.

210. All other deferral accounts, as provided in Schedules 24 and 25 of Appendix J-1, will continue as currently approved by Order G-44-12, and require no change for the purpose of amalgamation and postage stamp rates.[245]

9.2 No Basis for a Shareholder Contribution

211. The FEU were asked whether they would proceed with the amalgamation if the Commission "requires the FEU shareholder to make a financial contribution."[246] The FEU submit that the concept of a shareholder contribution is not an option in this proceeding. There is no provision of the *UCA* that provides the Commission with the power to order the shareholder to make a financial contribution. Moreover, such a contribution would have the effect of reducing the return of the shareholder on its investment. This would therefore contravene the absolute right of the shareholder to have an opportunity to earn a return on its investment as required under the *UCA*. The

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[243] Exhibit B-3, Application, p. 156.
[244] Exhibit B-15, BCUC IR 2.77.3.
[245] Exhibit B-3, Application, p. 156; Exhibit B-15, BCUC IR 2.75.1 and 2.75.2
[246] Exhibit B-15, BCUC IR 2.3.6.

appropriate return of the shareholder is addressed below under the topic of Cost of Capital.

9.3 Evidence of Mr. Robinson

212. Mr. Robinson filed two intervenor evidence submissions (Exhibit C11-4 and C11-5) and responses to information requests (Exhibits C11-6 and C11-6-1). The FEU's rebuttal evidence has responded to Mr. Robinson's evidence (Exhibit B-18). The FEU see two themes in Mr. Robinson's evidence: (1) that a reduction in rate base is warranted; (2) that the cost of service for the FEU is too uncertain to make a decision in this proceeding. Each of these themes will be addressed below following a discussion of Mr. Robinson's qualifications.

9.3.1 Qualifications of Mr. Robinson

213. In the FEU's respectful submission, Mr. Robinson has very limited regulatory experience and is not qualified to provide expert evidence on matters of rate design or cost of capital.

214. In his intervenor evidence, Mr. Robinson relies on his many years of experience at BC Hydro up until 1987. BC Hydro first became regulated by the Commission in 1980.[247] During the approximately 8 years during which BC Hydro was regulated and Mr. Robinson was employed by BC Hydro, Mr. Robinson was not a part of any regulatory department, but was a Supervisor of Budget Coordination and Manager of Accounting and Budgetary Control. While Mr. Robinson may have been involved in budgets and revenue requirement preparation, there is no evidence that Mr. Robinson was involved in any rate design proceeding. Mr. Robinson's description of the proceedings he was involved in fit the description of a revenue requirement proceeding rather than rate design. For example, he states: "I sat on committees that dealt with load forecasting and from these forecasts the rate department would develop the required rates to generate the revenue requirements that my department developed from the budgeting and planning process." Regardless of the nature of the proceedings, his involvement does not appear to be related to rate design, but to load forecasts and budgeting.[248] The rebuttal testimony of

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[247] Exhibit B-15, BCUC IR 2.7.1, footnote 10.
[248] Exhibit C11-6, FEU IR 1.2.

Mr. Gary Saleba indicates that Mr. Robinson has not relied on authorities followed by cost of service experts and has applied terms and concepts that are not appropriate from a cost of service and rate design perspective.[249]

215. Mr. Robinson acknowledges that he has no experience in return on equity or cost of capital proceedings.[250] While Mr. Robinson states that he has experience from the courses he teaches, these courses are related to cost accounting or finance and management accounting. There is no indication that Mr. Robinson has taught any course relevant to cost of capital from a distinctly regulatory perspective. The rebuttal testimony of Ms. Kathy McShane indicates Mr. Robinson has stated the wrong test for determining the cost of capital, misstated the effect of the Commission's determination of the fair rate of return and drawn conclusions that are "at odds with the fundamentals of regulation and the fair return standard".[251]

216. In the FEU's submission, Mr. Robinson's evidence and the FEU's rebuttal evidence demonstrate that Mr. Robinson has no expertise in regulatory, rate design and cost of capital matters.[252] While Mr. Robinson has expertise in cost accounting, cost accounting evidence is not relevant to this proceeding.[253] The FEU submit that the Commission should therefore accord very little weight to Mr. Robinson's evidence.

9.3.2 There is no Basis for a Reduction in Rate Base

217. In his intervenor evidence in Exhibit C11-4, Mr. Robinson expresses the view that there should be a reduction in FEVI and FEW's rate bases.[254] The FEU submit that there is no evidence or principled foundation to support this position and that it must be rejected.

218. First, the rate base of the FEU has recently been approved by the Commission in Order No. G-44-12, which set the rates for the FEU for 2012 and 2013. All of the FEU's

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[249] Exhibit B-18, Rebuttal Testimony of Mr. Gary Saleba of EES Consulting.
[250] Exhibit C11-6, FEU IR 1.2.
[251] Exhibit B-18, Rebuttal Testimony of Kathleen C. McShane.
[252] Exhibit B-18, Rebuttal Evidence.
[253] Exhibits C11-6 and C11-6-1
[254] Exhibit C11-4, pp. 13-14.

investments in rate base have been made in the provision of utility service and have been either explicitly judged by the Commission to be prudent or are presumed to be so.[255]

219. Second, the FEU submit that as the Commission has previously concluded, under sections 59 and 60 of the *UCA*, the FEU must be provided an opportunity to recover its reasonable and prudent cost of service and a fair return on its investment.[256] The Canadian courts have spoken on the utility's right to a fair return on its investment. In *Hemlock Valley Electrical Services Ltd. v. British Columbia Utilities Commission et al.*, [1992] 12 B.C.A.C. 1 at 20-21 (C.A.)), the B.C. Court of Appeal confirmed that the utility has a "statutory right to the approval of rates which will afford it the opportunity to earn a fair and reasonable rate of return upon the appraised value of its property."[257] In *Transcanada Pipelines Ltd v. Canada (National Energy Board),* 2004 FCA 149, the Federal Court of Appeal determined that the utility's cost of capital cannot take into account the impact on customers.[258] These decisions confirm that the utility's right to a fair return is, in the words of Justice Locke in *B.C. Electric Railway Co. Ltd. v. Public Utilities Commission of B.C.* [1960] S.C. R. 837, "absolute."[259]

220. Third, in the FEU's submission there is no evidence in this proceeding which could justify a reduction in the approved rate base of FEVI, FEW or FEI. Specifically, no evidence has been filed by any party including Mr. Robinson that shows that any particular assets of the FEU are not used and useful or were not prudently incurred. In response to the theories put forward by Mr. Robinson, the FEU submit the following:

(a) Mr. Robinson incorrectly theorizes that "declining demand volumes resulting from declining use per customer and declining Customer additions will, it can be inferred, result in lower than planned revenues hence lower future cash flows."[260] In fact, declining use per customer and declining customer additions would not normally result in reductions to future cash flows because of the forward-looking

[255] Exhibit B-9, BCUC IR 1.59.1.
[256] Exhibit B-9, BCUC IR 1.59.1.
[257] Exhibit B-9, Attachment 59.1.
[258] Exhibit B-9, Attachment 59.1.
[259] Exhibit B-9, Attachment 59.1.
[260] Exhibit C11-4, pp. 10-11.

cost of service based ratemaking methodology that is applied to the FEU.[261] As stated by Ms. McShane: "Mr. Robinson's comment that the utility rate base is overvalued based on future cash flows is at odds with the fundamentals of regulation and the fair return standard. Future cash flows are in large part determined by what the Commission allows, subject to competitive constraints."[262]

(b) Contrary to Mr. Robinson's assertions, FEI, FEVI and FEW do not have any impaired assets.[263] The FEU's criteria to monitor and identify asset impairment are aligned with US GAAP and the used and useful test.[264] No impairment charge was taken for the year ended December 31, 2011 in FEI, FEVI, or FEW's audited annual financial statements.[265] The FEU do not believe that FEVI or FEW are at risk of having an asset impairment issue at this point in time or in the foreseeable future.[266]

(c) Mr. Robinson's theory that FEVI's system has been overbuilt or is underused[267] is incorrect. FEVI's system has in fact been appropriately built to meet demand.[268]

(d) Mr. Robinson's theory that some of the rate base can be considered as Assets Held for Future Use[269] is unprincipled and opportunistic, as well as contrary to the FEU's capitalization policy and the BCUC's Uniform System of Accounts.[270]

(e) Contrary to Mr. Robinson's assertions, both FEVI and FEW are economically viable. Both FEVI and FEW continue to experience some customer growth and the companies do not forecast a large erosion of the customer base in the

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[261] Exhibit 18, Rebuttal Evidence of the FEU, Q&A 8, pp. 4-5.
[262] Exhibit 18, Rebuttal Testimony of Ms. McShane, pp. 2-3
[263] Exhibit B-9, BCUC IR 1.60.1, 1.60.1.1, 1.60.2 and 1.60.3
[264] Exhibit B-9, BCUC IR 1.60.1.1 and 1.60.2.
[265] Exhibit B-9, BCUC IR 1.60.3; Exhibit B-14, Attachment 7a; Confidential Exhibit B-14-1, Attachment 7b; Exhibit 18, Rebuttal Evidence of the FEU, pp. 3-5.
[266] Exhibit B-9, BCUC IR 1.61.1.
[267] Exhibit C11-3, pp. 4-5.
[268] Exhibit 18, Rebuttal Evidence of the FEU, pp. 8-11.
[269] Exhibit C11-4, pp. 11 to 12.
[270] Exhibit 18, Rebuttal Evidence of the FEU, pp. 5-7.

foreseeable future. The FEU therefore expect that there will be a sufficient customer base over which FEVI and FEW can collect their cost of service.[271] Since 2002, FEVI has successfully recovered its cost of service, paid off the RDDA and provided the shareholder with its approved return on equity.[272]

221. The FEU submit that based on the evidence in this proceeding it would be contrary to the regulatory compact to order a reduction in the rate base of the FEU. Ms. McShane states the following in her rebuttal testimony:[273]

> If the Commission were to require FEVI and/or FEW to remove assets from the rate base which have been previously found to be prudent, not only would such a requirement be contrary to the regulatory compact and precedent, it would materially raise the cost rates of both debt and equity capital, as well as potentially deterring any further investment in utility assets.

222. In summary, the FEU submit that there is no factual, legal or regulatory basis on which the Commission could order a reduction in the rate base of FEVI, FEW or FEI in this proceeding.

9.3.3 There is No Uncertainty in the Cost of Service

223. Mr. Robinson has also submitted intervenor evidence related to a number of cost of service issues, the point of which appears to be to show that there is uncertainty in the cost of service. In the conclusion of his “confidential” intervenor evidence, Mr. Robinson states:[274]

> The foregoing analysis of materials submitted to the commission by FortisBC Energy (Vancouver Island) Inc. indicates that there is a degree of uncertainty in the estimates and forecasts used in that utility. Any decision made with the information provided is too subjective to support a decision that will have a long lasting impact on customers in both [SIC] corporations FEVI, FEW, and FEI.

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[271] Exhibit B-9, BCUC IR 1.61.1.

[272] Exhibit B-18, Rebuttal Evidence of the FEU, pp. 3-5.

[273] Exhibit 18, Rebuttal Testimony of Ms. McShane, p. 3.

[274] Exhibit C11-5, p. 8.

224. The FEU submit that Mr. Robinson's conclusions are incorrect and his evidence is irrelevant to this proceeding.

225. First, Mr. Robinson's position reflects a fundamental misapprehension of the regulatory rate setting process. Generally, despite the fact there is some uncertainty in any forecast, the Commission determines the rates to recover what it determines to be a reasonable forecast cost of service for the utility.[275]

226. Second, Mr. Robinson's position is based on multiple incorrect assumptions and assertions related to the FEU's cost of service. Mr. Robinson's comments on shared services, rate stabilization accounts, main extensions, capitalized overhead and AFUDC and goodwill contain substantial errors and misunderstandings. The FEU's rebuttal evidence on the cost of service issues referenced by Mr. Robinson is, in summary, as follows:[276]

(a) The FEU's shared service costs are based on cost causation and approved by the Commission.

(b) The FEU's rate stabilization accounts are approved by the Commission and are established to decrease the volatility in rates caused by such factors as fluctuations in gas prices and the significant impacts of weather on use rates. The shareholder bears the risk of fluctuation in demand due to variances in customer additions.

(c) The FEU have been conducting main extensions in accordance with Commission-approved policies for at least 15 years.

(d) The FEU's capitalized overhead rate and AFUDC rate are approved by the Commission and are the same on a forecast and actual basis.

(e) Goodwill is not relevant to the cost of service.

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[275] Exhibit 18, Rebuttal Evidence of the FEU, pp. 4 and 15.
[276] Exhibit 18, Rebuttal Evidence of the FEU, Q&As 5-6 and 13-26.

227. All of the cost of service issues discussed by Mr. Robinson are issues that are dealt with routinely by the Commission in revenue requirement proceedings. Moreover, the Commission has approved the FEU's cost of service for 2012 and 2013 in Order No. G-44-12. The FEU submit that their cost of service is not uncertain in any relevant sense. There is also no reason why uncertainty in the cost of service would prevent the Commission from making a determination in this proceeding. In summary, Mr. Robinson's evidence on the cost of service is not relevant to this proceeding and his conclusions are without merit.

10.0 INTERIM COST OF CAPITAL

228. As part of the cost of service to determine the interim rate sought for January 1, 2014, the FEU are seeking approval of the cost of capital for FEI Amalco.[277] The FEU submit that the evidence in this proceeding establishes that FEI Amalco should have a 12 basis points premium over the benchmark ROE, which is currently 9.5%, and a capital structure of 40% equity and 60% debt. The FEU's proposal reflects the weighted average of the existing ROEs of the FEU and the current capital structure of the FEU. The FEU's proposal therefore reflects the status quo and is reasonable to approve on an interim basis until the GCOC Proceeding is complete.

229. Included in Appendix C-4 of the Application is the expert opinion of Ms. McShane regarding the impact of amalgamation on the cost of capital. The purpose of Ms. McShane's evidence is to address directionally how the amalgamation of the FEU, all else equal, would alter the cost of capital for FEI Amalco compared to FEI pre-amalgamation.[278] Ms. McShane's qualifications are attached as Attachment 1 to Appendix C-3 of the Application. As shown there, Ms. McShane has presented testimony in more than 200 proceedings on rate of return and capital structure in Canada and the U.S., including in proceedings before the Commission. The FEU submit that Ms. McShane is eminently qualified as an expert in cost of capital matters. No other expert evidence has been submitted in this proceeding challenging Ms. McShane's opinion.

230. As stated in Exhibit B-15, BCUC IR 2.3.6, while the FEU believe the 12 basis point risk premium is a reasonable premium over the current benchmark ROE, the FEU would proceed with amalgamation and postage stamp rates if it is determined by the Commission that FEI Amalco should have either a lower or no risk premium relative to the benchmark ROE.

10.1 Interim Rate Only

231. As indicated above, the FEU are requesting an interim rate for 2014. The interim rate is necessary with respect to cost of capital in particular since the Commission has initiated

[277] Exhibit B-3, Application, p. 157.
[278] Exhibit B-3-1, Appendix C-4, Opinion of Ms. McShane, p. 1.

the GCOC Proceeding. It is the Companies' understanding that the GCOC Proceeding will establish a benchmark ROE based on a benchmark utility effective January 1, 2013 to December 31, 2013, for the initial transition year. This determination will likely have implications for the risk premium for the Amalgamated Entity, which would be addressed in a future application following the GCOC proceeding.[279] Given the ongoing GCOC proceeding and contemplated subsequent proceedings to set risk premiums over the benchmark ROE, the FEU submit that approval of an interim rate, rather than a final rate, is appropriate at this time.

10.2 No Request to Change Common Equity Ratios for FEVI and FEW

232. The Companies are not requesting that the Commission increase the stand-alone common equity components of the capital structures of FEVI and FEW at this time.

233. The current common equity ratios for FEVI and FEW were confirmed as a result of the 2009 Return on Equity and Capital Structure proceeding. While neither FEVI nor FEW had applied for a change to their capital structures as part of the 2009 proceeding, the Commission acknowledged that both FEVI and FEW have greater long term business risk than FEI and directed those utilities to file evidence as to what equity component best reflects their respective long-term business risks.[280]

234. Both FEW and FEVI have undergone significant changes since the Commission set FEVI's equity thickness in 2006[281] and evidence has been provided on the appropriate equity thickness of FEW and FEVI as directed by the Commission in past orders.[282] As anticipated by the 2009 ROE Decision, the evidence, including the expert opinion of Ms. McShane, establishes that both FEVI and FEW face higher long-term business risks than the benchmark utility.[283] The evidence and the expert opinion suggest that an appropriate equity ratio for FEVI and FEW is 45%.[284]

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[279] Exhibit B-3, Application, p. 15 and pp. 157-158; Exhibit B-9, BCUC IR 1.56.2 and 1.56.3.
[280] Exhibit B-9, BCUC IR 1.64.3.1.
[281] Exhibit B-9, BCUC IR 1.67.3 and 1.67.3.1.
[282] Exhibit B-3-1, Appendices C-2 and C-3.
[283] Exhibit B-3, Application, p. 160.
[284] Exhibit B-3-1, Appendix C-3; Exhibit B-9, BCUC IR 1.64.3.1, 1.64.4, and 1.64.5.1.

235. If FEVI and FEW continue as separate utilities, they will apply for changes to their equity component and risk premium following the GCOC proceeding, making reference to both the characteristics of the benchmark utility that will be determined in that proceeding and the relevant risk factors prevalent at that time. Therefore, the FEU are not seeking any change to the FEVI and FEW equity thickness at this time.

10.3 No Change Requested to the Common Equity Ratio of FEI

236. For the purpose of interim rates, the FEU are proposing to maintain the current capital structure of FEI for FEI Amalco. The FEU submit that this proposal is reasonable and conservative and should be accepted.

237. The expert opinion of Ms. McShane supports an appropriate range for the common equity ratio for the amalgamated entity of 40% (FEI's pre-amalgamation cost of capital) to 41.2%. The 41.2% figure reflects the indicated weighted average common equity ratio of the three utilities, based on Ms. McShane's recommended stand-alone 45% equity ratios for FEVI and FEW discussed above.[285] For purposes of interim rates, the FEU submit that FEI's pre-amalgamation equity ratio of 40% is reasonable, if slightly conservative, for FEI Amalco.[286]

238. The FEU's proposal is reasonable even in the absence of any evidence that the appropriate equity ratio of FEVI and FEW is considered to be 45% as recommended by Ms. McShane. Ms. McShane suggests that an appropriate range for the common equity ratio for the amalgamated entity is bounded at the lower end of the range by FEI's common equity ratio pre-amalgamation and at the upper end of the range by the weighted average of the appropriate stand-alone equity ratios of FEI pre-amalgamation, and FEVI and FEW on a stand-alone basis. If the appropriate equity thickness for stand-alone FEVI and FEW were hypothetically 40%, this would only lower the upper end of the range to 40% without having any impact on the lower end of the range. Therefore, even if the appropriate equity ratios of FEVI and FEW are considered to be 40%, the proposed

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[285] Exhibit B-9, BCUC IR 1.64.1.
[286] Exhibit B-9, BCUC IR 1.64.1.

lower end of the range for FEI Amalco of 40 percent remains appropriate, given that amalgamation will not lower FEI's cost of capital.[287]

239. The FEU therefore submit that the Commission need not draw any conclusions on whether the appropriate equity thickness of FEVI and FEW is 45% as recommended by Ms. McShane in order to conclude that the proposed common equity ratio of 40% for FEI Amalco is reasonable. In summary, the common equity ratio of 40% represents the current common equity ratio for FEI, FEVI and FEW and is a reasonable and conservative ratio to adopt for FEI Amalco on an interim basis pending the outcome of the GCOC proceeding.

10.4 Proposed Risk Premium For FEI Amalco

240. The FEU submit that a risk premium 12 basis points above the current benchmark ROE is appropriate for FEI Amalco.

241. According to Ms. McShane's opinion, amalgamation does not create any meaningful diversification for FEI Amalco, and, FEI Amalco will assume some of the FEVI and FEW long-term business risks and thus will face a higher risk than the benchmark utility, FEI. Ms. McShane concludes that the post amalgamation return on equity should be in the higher end of the range of 9.50%-9.62%. Ms. McShane opines as follows:[288]

> At the lower end of the range, the post-amalgamation cost of capital for FEI is at least equal to FEI's cost of capital pre-amalgamation, since the folding in of the two smaller utilities does not lower FEI's cost of capital. The upper end of the range reflects the weighted average of the costs of capital of the three utilities on a stand-alone basis. As regards the return on equity, the allowed ROE for FEI is currently 9.50%; the allowed ROE for both FEVI and FEW is 10.0%. The weighted average ROE (based on the forecast 2013 rate bases of the three utilities) is 9.62%. The resulting range of ROEs for FEI post-amalgamation is approximately 9.5% to 9.6%.
>
> In principle, the transfer of certain of the FEVI's and FEW's utility-specific business risks to FEI, and the overall impact of rate

[287] Exhibit B-15, BCUC IR 2.21.3.
[288] Exhibit B-3-1, Appendix C-4, pp. 10 and 11.

> harmonization on the competitive risks of FEI suggest that FEI's post-amalgamation cost of capital would be modestly higher than the cost of capital for the benchmark utility (i.e., FEI pre-amalgamation) and thus both the ROE and common equity ratio for FEI post-amalgamation should be toward the upper end of the range.

242. Ms. McShane's specific conclusions supporting her recommendation, as found at pages 11 to 13 of her opinion, are summarized below.

(a) The amalgamation of the three utilities, from a capital markets perspective, would not alter the relative size of FEI to a degree that would alter its cost of capital.

(b) The proposed amalgamation does not result in any meaningful diversification for FEI, given the broad spectrum of business-risk related characteristics that are common to all three utilities. Thus, FEI Amalco's cost of capital would lie in a range bounded by the benchmark, i.e. FEI's pre-amalgamation, cost of capital at the lower end and the weighted average of the pre-amalgamation costs of capital of the three utilities at the upper end.

(c) Certain business risks unique to FEVI and FEW transfer to the amalgamated FEI, increasing FEI's post-amalgamation cost of capital relative to the benchmark utility, i.e., FEI pre-amalgamation.

(d) Harmonization of rates with amalgamation will improve the competitive pricing position of the former FEVI and FEW service areas versus electricity, but will modestly weaken the competitive position of the Mainland service area. The slightly higher post-amalgamation price competitive risks of FEI Amalco indicate, directionally, a higher post-amalgamation cost of capital for FEI Amalco.

(e) The transfer of certain of FEVI's and FEW's utility-specific business risks to FEI, and the overall impact of rate harmonization on the price competitive risks of FEI point to a modestly higher cost of capital for FEI Amalco than for the benchmark utility (i.e., FEI pre-amalgamation), and hence both the ROE and common equity ratio for FEI Amalco should be toward the upper end of the range.

243. Ms. McShane's conclusions are discussed in more detail below.

10.4.1 Impact of Amalgamation on Size and Cost of Capital

244. In section III of her opinion, Ms. McShane describes how the size of a firm can have an impact on its cost of capital. The question is whether FEI Amalco would be perceived by the capital markets as materially larger than pre-amalgamation FEI. Ms. McShane tests whether FEI Amalco would be perceived as materially larger than pre-amalgamation FEI by comparing the capitalization of pre-amalgamation FEI and FEI Amalco to an analysis of firm size and costs of capital performed annually by Morningstar/Ibbotson Associates. The results of this comparison show that both pre-amalgamation FEI and FEI Amalco would qualify as large cap stocks and would most likely fall within the same market capitalization decile. As stated by Ms. McShane: "In other words, while FEVI and FEW (combined) are not of immaterial size, FEI has already reached sufficient market capitalization such that, from a capital markets perspective, the increase in size arising from amalgamation would not lower its cost of capital."

245. Ms. McShane's opinion on this point was tested in information requests, but in the FEU's submission, these information requests raise no issues.[289]

10.4.2 Impact of Amalgamation on Diversification and Cost of Capital of FEI

246. In section IV of her opinion, Ms. McShane describes how a lower cost of capital has been associated with a diversification among business segments, e.g. different but related lines of business, and where the cash flows from the different lines of business are less correlated. As explained by Ms. McShane, when there is a low correlation of cash flows, if there is a reduction in cash flows from one business segment, it is less likely that there will be a corresponding reduction in cash flows from another segment. The degree of correlation depends on how similar or different the factors are that drive the individual segments' cash flows.

247. Ms. McShane considers the similar characteristics of the FEU that determine their short-term and long-term business risks and concludes:[290]

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[289] Exhibit B-9, BCUC IR 1.65 series and 1.69.1; Exhibit B-15, BCUC IR 2.22 series.

> Given all the similarities in the fundamental characteristics (e.g. same provincial economy, same provincial energy policy, similar competitive pressures, same regulator) of each of the FortisBC Energy Utilities, the cash flows will be highly correlated. With a high degree of correlation in cash flows among the three individual utilities, amalgamation does not create any meaningful diversification for FEI.

248. In short, the proposed amalgamation does not result in any meaningful diversification for FEI given the correlation in cash flows of the FEU. Ms. McShane's opinion that the correlation of cash flows is likely to be highly correlated is supported by an historical analysis of cash flows showing a high degree of correlation.[291]

249. Ms. McShane's observations regarding the similarities in the fundamental characteristics of the FEU relate to exogenous factors.[292] As utilities operating in British Columbia, all three utilities are affected by the broad economic and demographic trends in British Columbia, and thus are subject to similar economic influences and pressures, as well as being similarly affected by other factors that are inter-related with the provincial economy, e.g., the competitive landscape and provincial energy policy.[293] Two utilities operating in the similar environments, however, may have different business risks due to utility-specific factors.[294]

250. For example, the FEU are subject to "similar competitive pressures" meaning that the sources of the competitive pressures are similar, e.g., competition from electricity and other sources of energy, and the impacts of energy policy on customer preferences and choices. It does not follow that the degree to which those competitive pressures impact each utility is the same. All three of the utilities experience competition from similar alternative energy sources; however, the competitive risks are higher for FEVI and FEW than for FEI.[295]

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[290] Exhibit B-3-1, Appendix C-4, p. 7.
[291] Exhibit B-15, BCUC IR 2.23.1 and 2.23.4.
[292] Exhibit B-9, BCUC IR 1.67.5.
[293] Exhibit B-9, BCUC IR 1.67.6.
[294] Exhibit B-9, BCUC IR 1.67.5.
[295] Exhibit B-9, BCUC IR 1.67.7.

251. Ms. McShane explains that the lack of any meaningful diversification indicates that, in the context of portfolio theory, the required return for FEI post-amalgamation would be equal to the weighted average of the three individual utilities' pre-amalgamation returns. Ms. McShane concludes:

> In sum, given the absence of any meaningful diversification created by amalgamation, FEI's post-amalgamation cost of capital lies within a range, bounded at the lower end by FEI's pre-amalgamation, i.e. the benchmark, cost of capital and at the upper end by the weighted average of the pre-amalgamation costs of capital of the three individual utilities.

252. The FEU submit that this conclusion is reasonable and should be accepted.

10.4.3 Transfer of Business Risk to FEI

253. Having established the range within which FEI Amalco's cost of capital lies, Ms. McShane next considers whether any business risks transfer from FEVI and FEW to FEI upon amalgamation. She concludes that certain business risks unique to FEVI and FEW do in fact transfer to the amalgamated FEI, increasing FEI's post-amalgamation cost of capital relative to the benchmark utility, i.e., FEI pre-amalgamation. Ms. McShane explains as follows:[296]

> Certain risks that distinguished FEVI and FEW from the benchmark utility, i.e., FEI pre-amalgamation, do not disappear as a result of amalgamation. Instead, with amalgamation, certain risks unique to FEVI and FEW that caused their cost of capital to exceed that of the benchmark utility will be, to a large extent, transferred to FEI post-amalgamation. To illustrate, while FEVI will no longer exist as a separate corporate entity, a material portion of FEI's post-amalgamation service area will still be maturing and thus exposed to the risks associated with a maturing market. The risks associated with FEW's highly concentrated (in the tourism industry) customer base also transfer to FEI. The higher supply disruption risk faced by FEVI (due to its island location) and by FEW (due to its dependence on the Whistler Pipeline) than the benchmark utility is not subsumed by amalgamation. Instead, FEI post-amalgamation will face somewhat higher supply risk than pre-amalgamation.

[296] Exhibit B-3-1, Appendix C-4, pp. 9-10.

254. A further example of the transfer of business risks to FEI upon amalgamation was provided in response to BCUC IR 1.67.6.1 as follows:

> Regarding tourism, the industry is a major contributor to the British Columbia economy; according to Tourism British Columbia, it is the largest contributor to the province's real GDP of the primary resource industries. The tourism industry includes accommodation and food services, transportation and retail activities, all sectors that are served by pre-amalgamation FEI. A downturn, or a secular decline, in a major contributor to the B.C. economy would have a negative impact on the throughput of pre-amalgamation FEI. Amalgamation of FEW, whose exposure to the tourism industry is significantly higher than pre-amalgamation FEI's, will tend to increase FEI's exposure to negative events in the tourism industry.[297]

255. A comprehensive list of the risks unique to FEVI and FEW and whether they will be eliminated or mitigated upon amalgamation are discussed in table format in response to BCUC IR 1.70.1.[298]

256. As concluded by Ms. McShane, "The transfer of certain business risks unique to FEVI and FEW to FEI upon amalgamation indicates that FEI's cost of capital post amalgamation will be marginally higher compared to the benchmark utility, i.e., FEI pre-amalgamation."

10.4.4 Impact of Changes due to Harmonization of Rates

257. A second factor considered by Ms. McShane to assess how to best situate FEI Amalco's cost of capital within the range is how, if at all, any changes that will accompany amalgamation impact FEI's post-amalgamation cost of capital.[299] The principal change that will occur is the harmonization of rates and Ms. McShane considers the shift of competitive pressures that may occur as a result. She concludes that the harmonization of rates with amalgamation will improve the competitive pricing position of the former FEVI and FEW service areas versus electricity, but will modestly weaken the competitive position of the Mainland service area. Overall, the slightly higher post-amalgamation

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[297] Exhibit B-9, BCUC IR 1.67.6.1.

[298] Exhibit B-9, BCUC IR 1.70.1.

[299] Exhibit B-3-1, Appendix C-4, Opinion of Ms. McShane, p. 8.

price competitive risks of FEI Amalco indicate, directionally, a higher post-amalgamation cost of capital for FEI Amalco.[300]

258. As the FEU have emphasized throughout the evidentiary record, rate harmonization will improve the competitiveness of natural gas in the former FEVI and FEW service areas *from a strictly price (operating cost) perspective*[301] and that price differences in competing energy forms are not the only factor that determines competitiveness.[302] Thus, while in theory the proposed rate changes, all else equal, could lead to a change in capture rates, the price competitiveness of one energy form against another is just one factor that can impact capture rates. This is shown historically where capture rates have been high in periods of high gas prices.[303]

259. The FEU submit that, as concluded by Ms. McShane, a consideration of the impact of the harmonization of rates further supports the view that the appropriate return for FEI Amalco should be at the higher end of the range.

10.5 Conclusion on Interim Cost of Capital

260. Based on the considerations discussed above, Ms. McShane concludes:[304]

> In principle, the transfer of certain of the FEVI's and FEW's utility-specific business risks to FEI, and the overall impact of rate harmonization on the competitive risks of FEI suggest that FEI's post-amalgamation cost of capital would be modestly higher than the cost of capital for the benchmark utility (i.e., FEI pre-amalgamation) and thus both the ROE and common equity ratio for FEI post-amalgamation should be toward the upper end of the range.

261. The FEU submit that, subject to the outcome of the GCOC Proceeding, the evidence demonstrates that it is appropriate for FEI Amalco to have a 12 basis point risk premium over the benchmark ROE of 9.50%, with a 40 percent equity ratio.

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[300] Exhibit B-3-1, Appendix C-4, Opinion of Ms. McShane, p. 10-11. Also see Exhibit B-9, BCUC IR 1.58.2.

[301] Exhibit B-9, BCUC IR 1.58.2.

[302] Exhibit B-15, BCUC IR 2.19.3.

[303] Exhibit B-15, BCUC IR 2.19.4.

[304] Exhibit B-3-1, Appendix C-4, Opinion of Ms. McShane, p. 13.

11.0 RATE DESIGN

262. The FEU's proposed rate design and COSA study conducted by the FEU are described in detail in section 9 of the Application. The FEU retained Mr. Gary Saleba of EES Consulting, a multidisciplinary management consulting firm with particular expertise in rate design methodology and COSA modeling, to validate its rate design approach. Mr. Saleba's qualifications can be found as Attachment 1 to his opinion included as Appendix D-1 of the Application. Mr. Saleba has 40 years of experience as an economist and rate design expert and has been the President of EES Consulting for over 30 years. Over the course of his career, Mr. Saleba has provided expert testimony in numerous proceeding in the United States and Canada, including in previous Commission proceedings.[305] Mr. Saleba has confirmed that, in his expert opinion, the COSA methodology and model employed for the rate design are consistent with historical and industry practices and the results and conclusions derived are appropriate for the Amalgamated Entity.[306] No evidence has been filed in this proceeding challenging Mr. Saleba's conclusions.

263. Particular topics related to the proposed rate design that were explored during the proceeding are discussed below.

11.1 Customers Impacted by Postage Stamp Rate Design

264. The FEU's proposed postage stamp rates affect all residential, commercial and firm general service customers. Consistent with the 1993 Phase B Rate Design Application,[307] the FEU are not proposing any changes to large industrial and special contract customers that have specific rate structures and operating conditions. As stated in FEI's GT&Cs, such contracts are entered into when a minimum rate or revenue stream is required to ensure that service to the customer is economic or factors such as system by-pass opportunities exist or alternative fuel costs are such that a reduced rate is justified to keep the customer on-system.[308]

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[305] Exhibit B-3-1, Appendix D-1, Attachment 1.
[306] Exhibit B-3-1, Appendix D-1, EES Consulting, "FEU Natural Gas Cost of Service Review", April 2012.
[307] Exhibit B-9, BCUC IR 1.17.5.
[308] Exhibit B-9, BCUC IR 1.22.1.1.

265. For example, bypass rates are based on the customer's cost of constructing its own pipeline to bypass the system.[309] As these specific rates, rate structures and tariffs are still appropriate, the FEU are therefore not proposing any change.[310]

266. With respect to the FEVI customers BC Hydro and the Vancouver Island Gas Joint Venture ("VIGJV"), these are large industrial transportation customers that have unique, long-term contracts in place. FEVI and VIGJV have agreed to an amendment to the VIGJV Transportation Service Agreement (TSA), which extends the term but, in the case amalgamation is approved, provides the VIGJV with the option to terminate the TSA and take service pursuant to one of the rate schedules available to large industrial customers.[311] FEVI continues to work with BC Hydro on extensions and updates to its contracts appropriate for service with the Amalgamated Entity. If amalgamation is approved, FEVI will file the amending agreement with BC Hydro once it is executed.[312]

11.2 Use of FEI's Rate Design

267. The FEU are proposing to use FEI's rate structures and its underlying rate design methodologies for FEI Amalco. This approach is appropriate for the following reasons:

(a) Since the Amalgamated Entity customer base is primarily existing FEI customers, it is logical to carry over the rate design methodologies that currently are accepted and in use for FEI customers.

(b) It will result in fewer customers being impacted by changes in rate classes.

(c) The FEI rate structure and methodologies have been reviewed and approved by the Commission in the past.[313]

268. The FEU therefore submit that the use of FEI rate structures and methodologies is the most appropriate at this time for FEI Amalco. Questions regarding the existing FEI rate

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[309] Exhibit B-3, Application, pp. 136, 178, and 211.
[310] Exhibit B-3, Application, p. 178.
[311] Exhibit B-15, Attachment 26.1.
[312] Exhibit B-9, BCUC IR 1.26.1.
[313] Exhibit B-3, Application, pp. 179 to 184.

design can be addressed in a future rate design proceeding for FEI Amalco after sufficient time has passed for rate migration to occur.[314]

11.3 Mapping of Customers

269. As the FEU are proposing to use FEI rate structures, customers of FEVI, FEW and FEFN need to be transferred or mapped to an appropriate FEI rate schedule. The FEU's proposed mapping method is described in section 9.4 of the Application.[315] The FEU propose to move customers of the FEVI, FEW and FEFN utilities to FEI's Rate Schedules 1, 2 or 3. This is the same approach that was used in the mapping of Squamish customers in the amalgamation of Terasen Gas (Squamish) Inc. with FEI (then Terasen Gas Inc.) in 2007.

270. FEI's Rate Schedules 1, 2 and 3 are as follows:[316]

- Rate Schedule 1: Residential - includes service to all residential applications in single-family residences, separately metered single family townhouses, rowhouses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments.
- Rate Schedule 2: Small Commercial Service - serves customers with a normalized annual consumption at one premise of less than 2,000 Gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
- Rate Schedule 3: Large Commercial Service - serves customers with a normalized annual consumption at one premise of greater than 2,000 Gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.

271. The FEVI, FEW and FEFN rate schedules are described in Section 3 of the Application.

272. The FEU's mapping methodology was to map residential customers to Rate Schedule 1, where all other customers were mapped to Rate Schedule 2 or 3 depending on their annual consumption levels.[317] The table below shows how the FEVI, FEW and FEFN rate schedules would be mapped to FEI Rate Schedules 1, 2 and 3.[318]

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[314] Exhibit B-3, Application, p. 221 and Exhibit B-15, BCUC IR 2.58.1.
[315] Exhibit B-3, Application, pp. 185 to 188.
[316] Exhibit B-3, Application, p. 31.
[317] Exhibit B-3, Application, p. 185.
[318] Exhibit B-9, BCUC IR 1.23.1.

FEI Amalco Rate Class	FEVI Rate Class	FEW Rate Class	FEFN Rate Class
Rate Schedule 1	RGS	SGS Res	Res
Rate Schedule 2	AGS, SCS1,SCS2, LCS1	SGS Com, LGS 1	GSR 2.1, 2.2
Rate Schedule 3	AGS, LCS2, LCS3, HLF, ILF	LGS2, LGS 3	GSR 2.1, 2.2, R25

273. A narrative explanation of the effect of each of these changes to the FEVI, FEW and FEFN customers is provided in response to BCUC IR 1.23.2. Although mapped only to the rate schedules shown above, the other FEI rate schedules would be available to customers in Fort Nelson, FEVI and FEW upon amalgamation.[319]

274. The FEU submit that the methodology used to map the various entities' rate schedules into the amalgamated portfolio is the most appropriate approach. Rate Schedules 1, 2 and 3 do not require a written contract to be executed between FEI and the customer, making the transfer much more practical. Furthermore, some of the natural gas service offerings require the individual customers coming to business terms with the various natural gas marketers that serve the FEU customer base. As customers become educated on the various options available to them under the Amalgamated Entity, customers can then migrate to the various service offerings of their choice. For customers that elect Transportation Service, this option will be available to customers effective January 1, 2014 and Customer Choice will be made available no earlier than November 1, 2014.

11.4 Cost of Service Allocation (COSA) Study

275. FEI's existing and proposed rates are cost of service-based, meaning that the rates charged to customer classes recover costs associated with that class and the customers as a whole recover the utility's cost of service. In order to accomplish this for the proposed rates, a COSA study has been undertaken to allocate delivery and gas supply costs to the customer classes driving those costs based on cost causation principles. The FEU undertook the COSA study under the guidance of EES Consulting. EES Consulting has provided its expert opinion that the COSA study approach is appropriate and is based on industry accepted standards.[320]

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[319] Exhibit B-3, Application, section 9.4.1.1, p.185.
[320] Exhibit B-3-1, Appendix D-1, EES Consulting, "FEU Natural Gas Cost of Service Review," p. 5.

276. The FEU's COSA study followed a widely accepted three stage approach in which the costs and revenues of the utilities are functionalized into major categories, classified into three major cost causation factors, and then allocated to each rate class. The steps of functionalization, classification, and allocation are part of a well-established COSA methodology. By functionalizing costs from the forecast period revenue requirements, and then classifying those costs into customer-related, demand-related, and commodity-related costs, the COSA study allocates costs to the utility's customer classes based on those customers or customer groups that cause them. The costs allocated to each rate class are then compared with the class revenues. The resulting revenue to cost ratios are used as a gauge of the reasonableness of the revenues (and rates) associated with each rate class.[321]

277. The details of the COSA study are reviewed in pages 201 to 216 of the Application and in EES Consulting's expert report. Items related to the COSA study that were raised during the proceeding are discussed below.

11.4.1 Minimum System Study and Peak Load Carrying Capacity (PLCC) Adjustment

278. The Minimum System Study and PLCC Adjustment are used to determine the appropriate classification of Distribution Function costs. Distribution Function costs, such as mains, are borne both by customers connecting to the system (i.e. customer-related costs) and by the maximum hourly or daily gas flow requirements (i.e. demand-related costs). This approach is described in the Application and EES Consulting's report.[322] The study results are presented in Appendix D-3.

279. After concluding that classifying the distribution as 100% demand-related would be inappropriate, Mr. Saleba describes the minimum system approach as follows:[323]

> Distribution costs can also be split between demand and customer according to a minimum system approach. This approach reflects the philosophy that the system is in place in part because there are customers to serve throughout the service territory expanse, and

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[321] Exhibit B-3, Application, pp. 191 to 195.
[322] Exhibit B-3, Application, pp. 193-194 and 205-207; Exhibit B-3-1, Appendix D-1, pp. 13 to 15.
[323] Exhibit B-3-1, Appendix D-1, EES Consulting Report, p. 14.

> that a minimally sized distribution system is needed to serve these customers even if they only use 1 joule of energy per year. The concept follows that any costs associated with a system larger than this minimum size are due to the fact that customers "demand" a delivery quantity greater than the minimum unit of gas supply and that therefore, those costs should be treated as demand-related. Because the residential class tends to have a higher share of the number of customers as compared to the share of peak demand, the minimum system methodology tends to allocate more costs to the residential customer class and customer-related unit costs tend to be higher than with the 100% demand methodology.

280. The FEU's minimum system approach is consistent with industry practice and has been the consistent practice applied by the FEU for approximately 20 years.[324] In order to be consistent with past practice, the FEU chose to update the values used in the analysis but not update how the minimum system split was calculated.[325] An update to the approach applied by the FEU in this case was to increase the theoretical minimum system size to 2 inches, rather than the 1.25 inches used in the past.

281. The FEU then applied a PLCC adjustment. Mr. Saleba explains as follows:[326]

> While the minimum system is, in theory, designed to carry only a minimal amount of load, the actual facilities designated as the minimal size are actually capable of carrying some amount of demand, therefore overstating the level of the customer-related component. The actual amount of demand capability within the minimum system is a function of load density, minimum equipment standards, and other engineering considerations. Under traditional cost allocation techniques, each customer/connection attracts an equal allocation of the minimum system, plus each customer class is allocated demand costs based on the total customer class' peak demand. As such, it has been argued that a customer class' peak demand allocator is too large, because a portion of these peak demand-related costs are being covered through the per customer/connection minimum system allocation.
>
> The correction of the problem of over allocating demand can be achieved by the application of a PLCC adjustment. This adjustment recognizes that the minimum sized pipe assigned to the

[324] Exhibit B-9, BCUC IR 1.135.6.
[325] Exhibit B-9, BCUC IR 1.135.6.
[326] Exhibit B-3-1, Appendix D-1, EES Consulting Report, p. 15.

> customer-related component has a peak load carrying capability, that is, it is large enough to carry more than just the minimal amount of gas associated with having a customer on the system. The PLCC adjustment is made to the allocation of demand-related costs among customers. Use of the PLCC adjustment was recently approved by the Commission for the FortisBC electric COSA. This adjustment is particularly warranted in light of the change in the minimum size pipe to 2 inches as the new size allows an even greater amount of gas beyond the minimum requirement to flow to the customer.

282. The minimum system approach and PLCC adjustment are consistent. As explained in the response to BCUC IR 1.136.2, the Minimum System Study is intended to reflect a case where the Minimum Size of the system is based on 2” pipes. The PLCC is also based on a 2” Minimum Size system, which is consistent with the Minimum System Study approach and results. Because both the Minimum System Study and PLCC are theoretical calculations, it does not matter if there are actually pipes in place below the 2” minimum size. In any case, there is no difference in the average installed cost of pipe sizes 2” and below. The calculations are not intended to reflect an actual working system but are developed for the sole purpose of classifying and allocating the actual costs of the system.[327]

283. The FEU therefore submit that its minimum system approach and PLCC adjustment represent a reasonable classification of distribution costs and should be accepted.

11.4.2 Allocation of Revenues from Industrial, Contract Rates and Bypass Customers

284. The forecasted revenue associated with closed large industrial, contract rate and bypass service contract customers has been treated as Other Revenue and credited to the cost of service on the basis of revenue margin allocated to each Core Market and non-contract transportation service rate class. This approach is appropriate because the contract rate and bypass customers all have rates set in their respective contracts and as such are not subject to rate changes which result from the cost allocation process.[328] EES Consulting opines that the approach is appropriate:

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[327] Exhibit B-9, BCUC IR 1.136.2.

[328] Exhibit B-3, Application, p. 211.

> A large portion of other revenue comes from customer revenues that are set at negotiated rates. The FEU has customers on contract rates that have been negotiated due to the ability of the customer to bypass the system or because of the size and unique characteristics of the customer. This includes certain industrial customers that are on rates that have been closed and are no longer available to new large industrial customers. The cost of serving these customers is difficult to measure within the COSA and the rates are not directly based on the outcome of the COSA process. Generally such rates are set to recover the marginal cost of service plus some contribution to the fixed system. While these customers may not pay the full cost of service, they do provide a benefit to the remaining customers on the system. To ensure that all customers benefit from the revenues associated with these contracted customers, these other revenue items have been credited back to all other customers on the basis of the total margin. This approach is appropriate because it reflects the benefit of the load provided to the remaining customers, it reflects the fact that many of the contract customers do not use the distribution or storage systems to the extent of the remaining customers, and it allows revenue credits to flow to both core and transportation customers.

285. The fully embedded COSA does not measure the costs that are appropriate for these customers. Rather, using the revenues as an offset to the revenue requirements reflects a case where the costs are equal to the revenues. Because the contracted rates are designed outside the COSA to reflect the appropriate costs and benefits of serving these customers, those revenues best reflect the cost that should be allocated to these customers.[329] This method best reflects the true cost for all customers.[330]

11.4.3 Functionalization, Classification, Allocation of Tilbury Storage Function

286. The FEU are not proposing any change to the functionalization, classification and allocation of the Tilbury Storage facility from the approach reviewed and approved by the Commission in the past. The issue raised with respect to the treatment of Tilbury centered on the impact of LNG service through Rate Schedule 16.

287. The provision of LNG service through the Tilbury facility under Rate Schedule 16 does not require a change to the approach at this time. Specifically, the provision of

[329] Exhibit B-9, BCUC IR 1.137.1.
[330] Exhibit B-9, BCUC IR 1.137.4.

significant quantities of LNG under Rate Schedule 16 has no impact to the rate design methodology of the Tilbury facility and costs allocated to core natural gas customers as long as the costs and revenues associated to serve customers under Rate Schedule 16 are allocated in the same manner as proposed in the Application.[331] This is because the proposed COSA allocates costs associated with the storage facility and revenues generated from Rate Schedule 16 customers in the same manner without negatively impacting other natural gas customers.[332]

11.4.4 Functionalization, Classification, Allocation of Mt. Hayes LNG Storage Function

288. The Mt. Hayes Facility provides system capacity for FEVI (and indirectly to FEI) and is a peaking and seasonal gas storage resource in both the FEVI and FEI gas supply portfolios. The FEU's treatment of the Mt. Hayes LNG storage function is consistent with past practice and with the proposal in the CPCN application for the facility.[333]

289. Mt. Hayes is not used to offer LNG service under Rate Schedule 16. However, based on the proposed treatment of customers served under Rate Schedule 16, there will be no impact on the Amalgamated Entity COSA even with the Mt. Hayes storage facility being utilized to offer LNG service. The proposed COSA allocates costs associated with the storage facility and revenues generated from Rate Schedule 16 customers in the same manner without negatively impacting other natural gas customers.[334]

11.4.5 Treatment of Ratebase Related to the Purification of Biogas

290. The FEU's treatment in the COSA study of rate base related to the purification of biogas is consistent with the Commission's Decision on FEI's Biomethane Application, in which these costs were allocated to biomethane customers. As explained in response to BCUC IR 1.133.2, the rate base and cost of service associated with the Purification Plant is charged to the Biomethane Variance Account (Non-Rate Base Deferral account) and is recovered through the Biomethane Energy Recovery Charge (BERC rate) from customers

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[331] Exhibit B-9, BCUC IR 1.52.7.

[332] Exhibit B-9, BCUC IR 1.138.1 and BCUC IR 1.53.5.1.

[333] Exhibit B-3, Application, pp. 212-216; Exhibit B-9, BCUC IR 1.54.10.

[334] Exhibit B-9, BCUC IR 1.53.5.1 and 1.138.1.

who have enrolled in the Biomethane service. Since the Amalgamated COSA model does not include these customer classes, the Purification plant cost is not included in the COSA model and the corresponding depreciation provision is also netted to zero cost as well. This treatment is consistent with BCUC Order No. G-194-10, attached to the Commission Decision dated December 14, 2010, pages 48-51, where the Commission approved FEI's proposed approach to allocate to biomethane customers "the cost of purchasing Biomethane and raw biogas, including upgrading costs."[335]

11.4.6 Inclusion of Gas Costs

291. The COSA necessarily and appropriately includes gas revenues and costs in order to assess the rates for all rate classes. This is because the gas costs form a considerable part of the total cost of service. Therefore, even though the gas revenues and costs are a pass-through in the COSA model, they do have an impact on the overall revenue to cost ratios. The exclusion of gas revenues and costs from total revenues and total cost of service would reflect inappropriate revenue to cost ratios, making it difficult to assess if rates for any customer class are reasonable and adequate to recover their allocated cost of service.[336]

292. COSA studies generally take into consideration all costs, including pass-through gas commodity and midstream costs, to determine the appropriate revenues required to recover those costs. Based on EES' experience the inclusion of gas costs is within standard industry practice in the gas industry.[337] This approach is also consistent with FEI and FEVI previous rate design methodologies, which were reviewed and approved by the Commission.[338] The FEU therefore submit that its approach is reasonable and appropriate and should be accepted.

[335] Exhibit B-9, BCUC IR 1.133.2.
[336] Exhibit B-9, BCUC IR 1.74.5.3; Exhibit B-15, BCUC IR 2.59.1.
[337] Exhibit B-15, BCUC IR 2.59.1.1.
[338] Exhibit B-15, BCUC IR 2.59.1.1.

11.4.7 Conclusion on COSA Study

293. The FEU submit that its COSA study has appropriately functionalized, classified and allocated the costs of FEI Amalco. As shown above, the approach of the FEU's COSA study is consistent with industry practice and FEI's historical methodology. This provides the most rate stability for customers at this time. The FEU submit that the results of its COSA study are reasonable and should be accepted for the purpose of setting the postage stamp rates for the FEI Amalco.

11.5 Revenue to Cost Ratios and Range of Reasonableness

294. The FEU have presented and discussed the revenue to cost ratios resulting from the COSA study in section 9.7 of the Application. Since the COSA results are not precise, it is standard industry practice to use a range of reasonableness to determine at which point rate re-balancing is necessary, as determined by whether the Revenue to Cost ratios fall within or outside of the prescribed range.[339] The FEU have proposed no rebalancing based on a range of reasonableness of 90% to 110%.

295. Mr. Saleba supports the use of the FEU's range of reasonableness as follows:[340]

> The FEU has proposed using a 90% to 110% revenue to cost ratio "range of reasonableness" for setting proposed rates under the consolidation. We consider this to be a reasonable range for use when considering the adjusted revenue to cost ratios for the FEU. While this is a broader range than what is currently accepted by the Commission for the electric utilities in B.C., it is consistent with the range previously accepted for gas utilities in the Province and the larger range is appropriate in this particular case. Anytime there is greater uncertainty in the COSA results, the resulting revenue to cost ratios are less accurate and reliable. This makes it advisable to use +/- 10% to reflect the uncertainty in the COSA. The FEU COSA contains uncertainty due to several factors.
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> - First, gas utilities use peak days that reflect extreme weather planning conditions compared to the electric utilities that use actual or forecast loads under normal weather conditions. While the loads used in the FEU COSA

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[339] Exhibit B-3, Application, Section 9.7.1.2, p. 217 – 220.
[340] Exhibit B-3-1, Appendix D-1, p. 29-30.

> reflect the cost causation of the system, they contain less certainty than the loads used on the electric side. Because a large portion of costs are allocated on the basis of the peak day use per class, having uncertainty in the peak day loads used for allocation among the classes will lead to more uncertainty in the COSA results.
>
> - Second, the one-time consolidation of the FEU systems into one common revenue requirements and COSA creates the need to standardize the COSA methods, and in some cases the results will differ than if they had been done individually using past precedents. There are also some methods within the COSA that the FEU should review in future applications, as previously discussed, that may impact the results. Specifically, the lack of recognition of the contribution of nonfirm revenues towards the fixed cost of the system make the COSA results less accurate. Finally, the migration of all customers to the FEI rates creates additional uncertainty in the response to the new rates, which may impact customer gas use and the resulting load and revenue forecast.
>
> For those reasons, and to provide some operating history under the new consolidated rates prior to making major rate changes, the larger revenue to cost range is appropriate.

296. As noted by Mr. Saleba, the 90% to 110% Range is supported by previous Commission decisions for natural gas utilities in the province. For natural gas utilities, the long standing precedent for the "range of reasonableness" for the revenue to cost ratio has been 90 per cent to 110 per cent. In Commission Order No. G-42-91 that ruled on Ocelot Chemical's application seeking reconsideration of the Commission's ruling on Pacific Northern Gas's 1991 Rate Design Application (Order No. G-23-91), the Commission recognized the subjectivity inherent in cost allocation and concluded:

> Given the imprecision inherent in cost of service studies in general, and in particular the studies in issue, the Commission believes that as long as revenues from a particular class of service and costs allocated to that class of service do not differ by more than 10 percent, there is no compelling evidence to determine that the cost of service results indicate rate restructuring is required.

297. A range of reasonableness of 90 per cent to 110 per cent was used in the BC Gas 1993 Phase B Rate Design, and the Decision in that proceeding noted that: "In previous

decisions the Commission has accepted a 10 percent band as reasonable."[341] The same range of reasonableness was used in the BC Gas 1996 Rate Design and the Terasen Gas Inc. 2001 Rate Design Applications.[342]

298. In this Application, the FEU used a Range of Reasonableness for its class revenues to allocated cost of service of 90% to 110% rather than the Range of Reasonableness used for the electric utilities in BC of 95% to 105%. As described in the Application, this is appropriate as the accuracy of the system demand data is relatively imprecise compared to the system demand data used for electric utilities.[343]

299. The FEU are cognizant of the Commission's approach in the BC Hydro 2007 Rate Design Application Phase-1 Decision, which states (at p. 71):[344]

> The Commission Panel is further persuaded by the Intervenors' argument that under BC Hydro's approach of not making adjustments within its 90 percent - 110 percent band, those classes that start high will remain high and vice versa. Accordingly, the Commission Panel finds that the appropriate target for R/C ratios in each class is unity or one in this RDA, and that future rebalancing should only be required when a customer class falls outside of the range of reasonableness. [Emphasis added.]

300. The BC Hydro 2007 Rate Design Application Phase-1 Decision indicates that the Panel was persuaded by the argument that if some classes start high they stay high and vice versa. In the FEU's submission, it is imprecise to consider any rate class as being either "high" or "low," since this implies a level of precision that does not exist. To do so would defeat the reasons for applying a range of reasonableness, which is applied in acknowledgement of the lack of precision. Applying the range of reasonableness is to determine that any ratios within the range are reasonable and are on an equal basis with all ratios within the range.

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[341] Exhibit A2-2, BCUC Order G-101-93, BC Gas Utility Ltd. 1993 Phase B Rate Design Application Decision, dated October 25, 1993, at pp. 11-12.

[342] Exhibit B-3, Application, p. 220.

[343] Exhibit B-3, Application, Section 9.7.1.2, pp. 217 – 220.

[344] Accompanying Order G-140-07, dated October 26, 2007. Online at http://www.bcuc.com/Documents/Decisions/2007/DOC_17029_10-26_BCHydro-Rate-Design-Phase-1-Decision.pdf

301. The BC Hydro 2007 Rate Design Application Phase-1 Decision also indicates that in *that particular RDA* the appropriate target for R/C ratios was one. The Decision goes on to say that in future RDAs for BC Hydro rebalancing should only be required when the ratio is outside of the range of reasonableness. The Decision does not set out any general rule that the target should always be one. Nor is there any reason to apply such a rule to the present case.

302. The FEU therefore submit that the range of reasonableness of 90% to 110% is reasonable given the level of precision of its COSA and consistent with the Commission's past decisions for natural gas utilities. The FEU's approach is accepted by the expert opinion of Mr. Saleba and the FEU submit it should be accepted.

11.6 The Fixed Charge

303. The FEU are proposing to retain the existing residential basic charge that is currently applied to the approximately 775,000 FEI residential customers. The FEU submit that FEI's current basic charge is appropriate and that there is insufficient evidence or justification to change it at this time.

304. The regulatory history of FEI's basic charge is reviewed in Exhibit B-15, BCUC IR 2.39.1. Generally, the charge was postage stamped in 1993 and then increased in 1996 and 2001 to recover more of FEI's fixed customer-related costs. More recently, the fixed charge has remained constant while cost of service increases have been funnelled to the variable charge in order to improve energy efficiency awareness for customers. This history shows that there is a tension in setting the basic charge between several factors, including increasing the basic charge to recover fixed customer-related charges and increasing the variable charge to improve energy conservation awareness.

305. The move to FEI rate structures will result in more appropriate rate structures for the current FEVI, FEW and FEFN service areas. The current basic charge for FEVI, FEW and FEFN is lower than the basic charge for FEI, and FEFN currently has a declining block rate structure. By adopting FEI's rate structures for FEI Amalco, including a basic charge and flat energy charge, the basic charge will be increased for the current service areas FEFN, FEVI and FEW and replace the current declining block structure in place in

FEFN.[345] Moving to the postage stamp basic charge in FEVI, FEW and FEFN will move the basic charge more in alignment with the recovery of customer related costs in each area,[346] while replacing the FEFN declining block structure should improve energy conservation awareness.[347]

306. It would be premature to consider changing FEI's fixed charge at this time without a full consideration of the Bonbright principles, existing rate schedules, alternative customer charge levels, and a customer bill impact analysis by usage level. It is the intention of the FEU to consider any such changes in a subsequent application.[348] To consider the appropriate charge, the FEU would conduct market research, segmentation analysis and customer consultation that would all be factored into any rate design proposals at that time. The future proposals would give full consideration to multiple rate design principles including rate stability.[349]

307. The FEU's approach is supported by the opinion of Mr. Saleba who recommends that no other changes to rate design would be appropriate at this time. He states:[350]

> With consolidation, customers currently served under the distinct rates for FEVI, FEW and FEFN will all be transferred to the equivalent rates for FEI customers. It is the revenues at these consolidated rates that are used within the consolidated COSA for determining the revenue to cost ratios. This is an appropriate approach as the consolidated costs can only be compared to revenues under a consolidated scenario. As this is a significant change for many customers in terms of both the rate level and in some cases the rate design, it is recommended that no other rate design changes be made until these new rates are implemented and the utility ensures that all issues related to the rate migration are resolved. Changes to the rate design would be more appropriate to consider in future applications.

[345] Exhibit B-15, BCUC IR 2.39.3.
[346] Exhibit B-15, BCUC IR 2.39.1 and 2.39.7.
[347] Exhibit B-15, BCUC IR 2.39.3.
[348] Exhibit B-15, BCUC IR 2.39.5.
[349] Exhibit B-15, BCUC IR 2.39.7.1 and 2.39.7.4.
[350] Exhibit B-3-1, Appendix D-1, EES Consulting, "FEU Natural Gas Cost of Service Review", p. 30.

308. The FEU therefore submit that it would be inappropriate to change the FEI basic charge at this time.

11.7 Conclusion on Rate Design

309. The proposed rate design for FEI Amalco is consistent with past practice and FEI's existing rate structures and methodologies and has been confirmed by the expert evidence of Mr. Saleba as being appropriate at this time. The FEU therefore submit that the rate design should be approved as filed. The FEU reiterate that they will be revisiting the rate design for FEI Amalco in the future if the amalgamation is approved.

12.0 CONSULTATION

310. As described in Section 10 of the Application, the FEU consulted with customers and stakeholders through a variety of communication and consultation activities.

311. The Fort Nelson and District Chamber of Commerce appears to have some concerns regarding the communication of the potential rate impacts to Fort Nelson from amalgamation and postage stamp rates.[351] These rate impacts were communicated in a number of ways, including the following:

(a) The FEU met with representatives from the Northern Rockies Regional Municipality ("NRRM"), including the Mayor and Corporate Staff, to discuss common rates and amalgamation. Two meetings were conducted with the Mayor and Corporate Staff, one via teleconference, and one face-to-face in Fort Nelson.[352]

(b) The FEU held an Open House in Fort Nelson. The storyboards presented at the open house include rate impacts (Appendix E-12). Attendees at the Open House were also given a handout showing bill impacts (Appendix E-10). The Fort Nelson and District Chamber of Commerce and the NRRM attended the Open House.[353]

(c) The storyboards showing bill impacts were also made available on FEU's Common Rates webpage.[354]

(d) The web-based survey conducted by Vision Critical sought feedback on bill impacts.[355]

(e) Bill impacts were communicated through a bill insert sent to all customers as part of the notification for the Application.[356]

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[351] Exhibit C2-2, page 2.
[352] Exhibit B-3, Application, p. 226.
[353] Exhibit C2-3, p. 4.
[354] Exhibit B-3, Application, p. 227-228; Exhibit B-3-1, Appendix E-12.
[355] Exhibit B-3-1, Appendix E-5.

(f) The bill impacts are included in the Application, which was filed publicly.[357]

312. All interested parties were given until August 23, 2012 to register as intervenors in this proceeding, over 5 months from the time of filing the Application. The number of Interested Party Documents and Letters of Comments filed in this proceeding (see "D" and "E" Exhibits, respectively) demonstrates that customers have in fact been adequately notified of the Application and have been given an opportunity to participate in the proceeding.

313. The Fort Nelson and District Chamber of Commerce in particular has had ample opportunity to become fully informed of the Application and its impacts. After attending the Open House, the Fort Nelson and District Chamber of Commerce registered as an intervenor and filed two letters to the Commission in respect of the FEU's November 2011 Application that was later withdrawn. These letters are included in Attachment E-15 of the Application. The FEU compiled a response to the comments to these letters, which was sent to the Fort Nelson and District Chamber of Commerce.[358] The Chamber of Commerce has intervened and participated in this proceeding, including by filing written evidence. Appendices A and C to the Fort Nelson and District Chamber of Commerce's intervenor evidence show that it has had direct email correspondence with FEU staff in order to have its questions addressed.[359]

314. As indicated in FEU's Application and IR responses, the FEU's consultation activity with Fort Nelson all indicated that Fort Nelson customers are opposed to the Application.[360] In this respect, the petition filed by the Fort Nelson and District Chamber of Commerce supports the results of the FEU's consultation.[361] The wide support from FEVI and FEW customers in this proceeding similarly confirms the results of FEU's consultation.

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[356] Exhibit A-3, Appendix D to Order G-46-12.
[357] See, e.g., Exhibit B-3, Application, p. 6.
[358] Exhibit B-3-1, Appendix E-16 and Exhibit B-9, BCUC IR 1.106.2 and Exhibit B-9-1, Attachment 106.2.
[359] Exhibit C2-3, Appendices A and C.
[360] Exhibit B-3, Application, section 10.5; Exhibit B-9, BCUC IR 1.101.1.
[361] Exhibit C2-3, Appendix F.

315. The consultation efforts described above were part of the FEU's comprehensive consultation for the Application. The stakeholder engagement plan included communication and consultation with a broad range of stakeholders through a variety of activities, such as stakeholder meetings, public information sessions, market research, bill inserts, a dedicated web page, media outreach and customer letters. Through these activities stakeholders have been and will continue to be appropriately notified, consulted and informed about the proposed amalgamation and common rates.[362]

[362] Exhibit B-3, Application, pp. 236-241; Exhibit B-9 BCUC IRs 1.106.1 and 1.106.2.

13.0 CONCLUSION

316. The FEU submit that the evidence in this proceeding demonstrates that the proposed amalgamation is beneficial in the public interest and that the proposed postage stamp rates are just and reasonable. In accordance with section 53 of the *UCA*, the FEU request that the Commission determine that amalgamation of the FEU and THI is beneficial in the public interest and submit a report of its findings to the LGIC.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Dated: September 14, 2012

[original signed by Christopher Bystrom]
Christopher Bystrom
Fasken Martineau DuMoulin LLP
Counsel for the FortisBC Energy Utilities

BRITISH COLUMBIA UTILITIES COMMISSION

PROJECT NO. 3698652

FORTIS ENERGY UTILITIES
COMMON RATES, AMALGAMATION AND RATE DESIGN APPLICATION

BOOK OF AUTHORITIES OF

THE FORTISBC ENERGY UTILITIES

September 14, 2012

FASKEN MARTINEAU DuMOULIN LLP

I N D E X

1. BCUC Letter No. L-24-04, dated April 23, 2004

2. BCUC Order G-87-07, dated August 7, 2007, Appendix A

3. Commission Decision, FortisBC Inc. 2009 Rate Design and Cost of Service Analysis, dated October 19, 2010 (excerpt only)

4. Newfoundland and Labrador Board of Commissioners of Public Utilities, Order No. P.U. 14 (2004)

5. EUB Decision 2000-6 (February 2000)

6. EUB Decision 2003-052 (July 2, 2003)

7. EUB Decision 2003-090 (November 12, 2003)

8. Ontario Energy Board, RP-2005-0020, EB-2005-0409, Decision and Order dated April 28, 2006

9. Ontario Energy Board EB-2008-0222, EB-2008-0223

10. Order G-152-07 and accompanying Decision, System Extension and Customer Connection Policies Review, dated December 6, 2007 (excerpt only)

11. Bonbright, J., *Principles of Public Utility Rates*, second edition, 1988, pp. 381 - 395

ROBERT J. PELLATT
COMMISSION SECRETARY
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LETTER NO. L-24-04

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VIA FACSIMILE
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April 23, 2004

Mr. Mike Redfearn
Chief Administrative Officer
District of Chetwynd
Box 357
Chetwynd, B.C. V0C 1J0

Dear Mr. Redfearn:

Re: Terasen Gas Inc. ("Terasen Gas")
Complaint by the District of Chetwynd

In a letter dated December 18, 2003 the District of Chetwynd ("the District", "Chetwynd"), filed a complaint to the Commission pursuant to Section 58 of the Utilities Commission Act regarding Terasen Gas' rates for consumers within the District. The Commission, in its letter dated January 29, 2004, requested comment on the complaint from Terasen Gas and invited subsequent reply comment from the District. The Terasen Gas comment was received on February 20, 2004 and the District's reply was received on March 11, 2004.

In its complaint, the District submits that the rates for natural gas service to customers within the municipal boundaries of the District are unjust, unreasonable and unduly discriminatory, and requests that the Commission establish rates that are just, reasonable and sufficient. Alternatively, if the Commission cannot determine such rates, Chetwynd asks that the Commission require Terasen Gas to file sufficient information to enable the Commission to make such a determination.

The District's complaint arises in the context of negotiations regarding renewal of the operating agreement between the District and Terasen Gas. Chetwynd is currently served by Terasen Gas under an operating agreement dated May 22, 1980. That agreement expired on June 30, 2001 but has been extended by three separate one year extensions approved by the Commission. The District states that it cannot determine whether the renewal of the agreement is in the public interest of the residents of the District until the issue of rates is resolved.

The Commission notes that, while the context of the complaint may be the negotiations surrounding renewal of an operating agreement between Terasen Gas and Chetwynd, the District's complaint is specifically about the rates under which natural gas is supplied to its residents. Chetwynd submits that its complaint that rates to the district are too high is supported by cost of service analysis, comparison to rates in other communities in the region and by comparison to the cost of other fuels.

. . . /2

Terasen Gas supplies customers in the Lower Mainland, Inland and Columbia service areas. The delivery charges to Terasen Gas' customers are the same to each customer class throughout the three service areas ("postage-stamp rates"). The gas supply portion of Terasen Gas' rates are different for each service area to reflect some of the differences in the cost of supplying and transporting gas to each region. Chetwynd is located at the northern extreme of the Inland service area (which is north of the Lower Mainland and Columbia service areas).

Chetwynd provides data from the BC Gas 2001 Rate Design Application's Regional Cost Allocation Study to show that revenue to cost and margin to cost ratios were higher in the Inland North region (Chetwynd to Savona) than in the Lower Mainland, Inland South, and Columbia regions also served by Terasen Gas. While Chetwynd notes that revenue to cost ratios fall roughly within the ranges the Commission has traditionally considered acceptable, it argues that margin to cost ratios, which exclude the cost of gas, are a more appropriate indicator and that the margin to cost ratios are well beyond the range of reasonableness. A stand-alone analysis for the District, undertaken by Terasen Gas at the District's request, showed an overall margin to cost ratio of 1.3 with the majority of customers being close to one (residentials) and commercial and industrial customers being about 1.3.

Chetwynd and Terasen Gas disagree about the accuracy of the stand-alone analysis provided by Terasen Gas. Terasen Gas submits that the results of the stand-alone cost allocation exercise for Chetwynd and surrounding areas are insufficient to conclude that the rates for the customers in Chetwynd are unfair and unjust. Terasen Gas states that in the stand-alone analysis the residential margin to cost ratio is 1.02 and continues to support its conclusions in its last rate design application. Terasen Gas believes that Chetwynd's total cost as a separate utility would likely be higher due to its location and small size. Chetwynd further argues that Terasen Gas' stand-alone analysis is selective and based on a number of assumptions that make it difficult to assess the accuracy of Terasen Gas' analysis.

Chetwynd also compares its rates from Terasen Gas to those of the surrounding communities of Fort Nelson and Prince George, which are also served by Terasen, and to Fort St. John, Dawson Creek and Tumbler Ridge, all served by Pacific Northern Gas Ltd. Based on April 1, 2003 rates, Chetwynd's rates are higher than those of Fort Nelson, Dawson Creek and Fort St. John, the same as those in Prince George and lower than those in Tumbler Ridge.

Further, Chetwynd submits that the natural gas rates in Chetwynd are approaching and may exceed the efficiency adjusted price of electricity for space heating, depending on the assumed efficiency of the gas furnace.

<u>Commission Determinations</u>

Allocating the total cost of service among the different ratepayers so as to avoid arbitrariness and cross-subsidization is important, but not the only factor to be considered when determining the reasonableness of rates. Other important factors include administrative simplicity, understandability and stability of rates.

The Commission notes that the District found the revenue to cost ratios provided in the BC Gas 2001 Rate Design Application to be within the range of reasonableness, although it had greater concerns about the margin to cost ratios. The Commission also notes that Terasen Gas and Chetwynd differed on the accuracy of the stand-alone cost analysis.

The BC Gas 1993 Rate Design Decision endorsed "postage-stamp" rates as appropriate across the Lower Mainland and Inland service areas. The 2001 settlement agreement (approved by the Commission and attached to Order No. G-116-01) in the matter of the BC Gas 2001 Rate Design Application was silent on the issue of postage-stamp versus regional rates, but accepted postage-stamp rates applicable to the delivery charges for the Lower Mainland, Inland and Columbia service areas.

The Commission is not persuaded that the cost of service analysis provides sufficient justification to require Terasen Gas to amend the rates to the District of Chetwynd. As noted above, there are other important considerations to consider when setting rates such as administrative simplicity, stability and understandability. To set a rate for a single municipality or district raises serious issues about how far the boundaries of the rates should extend, and how the utility would adjust its rates for other customers if the rates to one district were changed. The appropriate forum for considering the rates charged to various customer classes (whether those classes are defined by geographic area or by customer characteristics) is within a rate design hearing so that other affected customers may respond, as well as the utility. Therefore, the Commission dismisses Chetwynd's complaint.

The Commission acknowledges the District's position that, even though there is some regional differentiation in the gas supply portion of Chetwynd's rates, those rates still may include some Duke Energy Transmission tolls and fuel gas charges for services that Chetwynd doesn't need. This could occur because of Chetwynd's location just north of Station 2 on the Duke Energy Transmission system. Therefore, if Chetwynd wishes to raise this issue in the next Terasen Gas Rate Design proceeding, it is invited to do so.

Yours truly,

Original signed by:

Robert J. Pellatt

JWF/mmc

cc: Mr. Scott Thomson
Vice President, Finance and Regulatory Affairs
Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C. V3S 2X7

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER NUMBER G-87-07

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473
and
An Application by FortisBC Inc.
for a Rate Design on the Big White Supply Project

BEFORE: L.A. Zaozirny, Panel Chair August 7, 2007

O R D E R

WHEREAS:

A. On March 9, 2006, FortisBC Inc. ("FortisBC") applied to the British Columbia Utilities Commission ("Commission") for a Certificate of Public Convenience and Necessity ("CPCN") to construct and extend a 34 km, 138 kV transmission line from the Joe Rich Substation to a new substation to be built at the Big White Village at a cost of $20.32 million, including approximately 23 km of new transmission line (the "Project"); and

B. Following an Oral Public Hearing process the Commission, on September 14, 2006 by Order No. C-17-06 and Reasons for Decision, granted a CPCN to FortisBC for the construction of the Big White Supply Project subject to a condition related to a risk sharing mechanism; and

C. Commission Order No. C-17-06 and Reasons for Decision also directed FortisBC to file, within 90 days of the Decision, an application for a rate design for the Project which considers the circumstances and conditions pertaining to the Project, and which would be the subject of a separate proceeding and a determination by the Commission as to how the costs of the Project will be recovered; and

D. On October 10, 2006 and October 12, 2006, Big White Ski Resort Ltd. and FortisBC, respectively, applied for a reconsideration of certain aspects of the Commission's Decision related to a CPCN for the Big White Supply Project; and

E. By Order No. G-154-06 and Reasons for Decision, the Commission denied the Reconsideration Applications and clarified that the intent of the direction in the Reasons for Decision attached to Order No. C-17-06 was that FortisBC, in a first stage of the process, would make an application to the Commission addressing two primary questions: (1) should some or all customers of the Big White area, as distinct from all FortisBC ratepayers, be required to fund some or all of the costs of the Project; and (2) if total funding from all FortisBC ratepayers is not required, then how should the funding from the customers of the Big White area be determined and allocated?; and

F. F. On March 6, 2007, FortisBC filed a Rate Design Application for the Project (the "Application") pursuant to Orders No. G-17-06 and G-154-06 and requested that a Procedural Conference be convened to address procedural matters and to establish a Regulatory Timetable and, in particular, to address the process for public consultation necessary prior to the Company making its recommendations on cost recovery methodology and the disposition of the Application; and

…/2

G. By Order No. G-30-07, the Commission determined that a Public Notice should be issued and a Procedural Conference be held on April 16, 2007 in Kelowna, B.C. to consider the further process to be established to review FortisBC's Rate Design Application; and

H. On April 13, 2007, as required by Order No. G-30-07, FortisBC filed its response to an initial Commission Information Request; and

I. FortisBC, in its opening remarks during the Procedural Conference, suggested that its Application and the responses to the Commission's Information Request constitute new information that raises a preliminary issue of "whether or not there is still a serious question as to whether Big White customers should be paying some or all of those project costs" ("Preliminary Question") and FortisBC proposed that a written submission process be established to consider this new information and Preliminary Question.

J. On April 23, 2007, following the Procedural Conference, and after having heard submissions from parties concerning the regulatory process and FortisBC's Proposal, the Commission issued Order No. G-46-07 issuing a Revised Regulatory Timetable for a written submission process to review the new information and the Preliminary Question; and

K. Submissions on the Preliminary Question were received from FortisBC on June 8, 2007, and from BCOAPO on June 21, 2007, and from Big White Ski Resort Ltd. and Mr. Alan Wait on June 22, 2007. FortisBC filed its Reply Submission on June 28, 2007; and

L. The Commission has considered the evidence and submissions of FortisBC, BCOAPO, Big White Ski Resort Ltd. and Mr. Wait and issues its Reasons for Decision.

NOW THEREFORE the Commission approves the inclusion of the Project costs in the FortisBC rate base as proposed by FortisBC and as set out in the Reasons for Decision, attached as Appendix A.

DATED at the City of Vancouver, in the Province of British Columbia, this 9th day of August 2007.

BY ORDER

Original signed by

L.A. Zaozirny
Commissioner

Attachment

AN APPLICATION BY FORTISBC INC.
FOR A RATE DESIGN ON THE BIG WHITE SUPPLY PROJECT

REASONS FOR DECISION

1.0 BACKGROUND

1.1 The Big White Supply Project

On March 9, 2006 FortisBC Inc. ("FortisBC", "Company", "Utility") applied to the British Columbia Utilities Commission ("Commission", "BCUC") for a Certificate of Public Convenience and Necessity ("CPCN") for the Big White Supply Project (the "CPCN Application"). The Big White Supply Project involved the construction of 23 km of new 138 kV line, the reinsulation of 11.3 km of an existing section of line from the Joe Rich substation, a new substation located at the Big White development area ("Big White") and distribution upgrades at Big White ("the Project"). The capital cost associated with the Project is estimated by FortisBC at $20.32 million.

Big White is a community located approximately 50 km southeast of Kelowna. Big White Ski Resort Ltd. ("BWSR") owns and operates a ski resort at Big White (Exhibit C5-1, T1:37).

1.2 The Review of the CPCN Application and the Related BCUC Decision

Following receipt of the CPCN Application the Commission, by Order No. G-44-06, established a Regulatory Agenda and Oral Public Hearing to review the Application. The Oral Public Hearing commenced on July 4, 2006 and concluded on July 5, 2006. After the hearing and the submission of argument and reply argument, the Commission issued its Decision dated September 14, 2006 ("CPCN Decision") and Order No. C-17-06 granting a CPCN for the Project subject to FortisBC agreeing to accept a risk sharing mechanism for the Project.

The CPCN Decision also stated, on page 27, that:

> "The Commission Panel determines that the circumstances and conditions found at Big White are sufficiently unique that it should not be considered a community in the same sense as many other communities in the FortisBC service area.
>
> Accordingly, for purposes of determining the appropriateness of sharing the costs of the Project amongst all ratepayers, special consideration is warranted."

On page 35, the Decision stated that:

> "FortisBC is directed to file, within 90 days of this Decision, an application for a rate design for the Project which considers the circumstances and conditions pertaining to this Project. That application will be the subject of a separate proceeding and a determination by the Commission as to how the costs of the Project will be recovered.
>
> FortisBC is directed to establish a deferral account for the Project. The deferral account will accumulate the costs of the Project, together with related AFUDC, to be recovered by FortisBC as determined by the Commission in conjunction with the application for a rate design for the Project."

1.3 Reconsideration Applications and the BCUC Decision

On October 4 and October 12, 2006, BWSR and FortisBC, respectively, applied to the Commission for reconsideration and variation of Order No. C-17-06 and the Decision. FortisBC applied for reconsideration of, among other things, reconsideration of the Decision with respect to the directions regarding the Rate Design Application to be filed by the Utility and the establishment of a deferral account for the accumulation of the costs of the Project. Among the submissions in its Reconsideration Application, BWSR submitted that the Order did not accord with the CPCN Application and that there was inadequate notice of the cost recovery issue and a lack of jurisdiction to order a contribution from customers.

The Commission established a written comment process to determine whether or not BWSR and FortisBC had established a *prima facie* case sufficient to warrant full reconsideration of the matters by the Commission. On December 6, 2006, the Commission issued Order No. G-154-06 and Reasons for Decision denying the BWSR and FortisBC Reconsideration Applications ("Reconsideration Decision"). However, in its Reasons for Decision the Commission stated that FortisBC had raised issues in the course of its reconsideration application that the Commission would address by way of clarification.

In the Reconsideration Decision, the Commission noted that while the need for the Project had been established to warrant approval and the issuance of a CPCN, the Commission did not in the CPCN proceeding receive sufficient evidence on which to make a decision on the appropriateness of, and/or a methodology for, sharing the costs of the Project amongst all or any specific group of ratepayers or customers. Consequently, the Commission ordered that the issue of recovery of some or all of the costs of the Project should be brought forward by way a separate application and proceeding. With respect to its use of the term 'rate design', at page 35 of the September 14, 2006 Decision, the Commission stated that this term, as used in the Decision, was generic and was purposefully non-specific regarding what FortisBC should bring forward, other than it should focus on "… the circumstances and conditions pertaining to this Project".

The Commission further commented that because of the unique aspects of this Application, it was not persuaded that a Fully-Allocated Cost of Service study leading to a general consideration of regional rates is required at this time:

> "Simply put, FortisBC is enhancing its service to Big White in large part by upgrading a distribution service to a transmission service, to service a discrete area that appears to be unique insofar as the enhanced service appears to primarily support continued development driven by BWSR. Therefore, the direction of the Commission was intended that FortisBC, in a first stage of the process, would make an application to the Commission addressing two primary questions:
>
> 1. Should some or all customers of the Big White area, as distinct from all FortisBC ratepayers, be required to fund some or all of the costs of the project?
>
> 2. If total funding from all FortisBC ratepayers is not required, then how should the funding from the customers of the Big White area be determined and allocated?
>
> FortisBC may wish to consider the cost of the Project and the degree to which those costs are likely to be recovered from the ratepayers in Big White in the future. FortisBC may also wish to consider the basis on which the project costs for the initial and/or enhanced distribution and/or transmission services to like areas and facilities in its service territory have been recovered in the past."

With that clarification, the Commission directed FortisBC to file its Application for a rate design for the Project within 90 days of the date of the Reconsideration Decision.

1.4 Process for Review of the FortisBC Rate Design Application

On March 6, 2007, FortisBC filed its Rate Design Application ("Application") for the Project. In the Application, FortisBC requested that a Procedural Conference be convened to address procedural matters and to establish a regulatory timetable "… and, in particular, to address the process for public consultation necessary prior to the Company making its recommendations on cost recovery methodology and the subsequent disposition of the application" (Exhibit B-1, p. 4).

The Commission Panel assigned to consider the Application issued Order No. G-30-07 (Exhibit A-1) on March 16, 2007 and established a Procedural Conference to be held in Kelowna on April 16, 2007 and an initial round of Commission Information Requests for which FortisBC was required to file a response by April 13, 2007. At the Procedural Conference FortisBC, relying upon information contained in its Application and responses to Commission Information Request No. 1, proposed "… that there be a written process, given that there is new information in front of the Commission on whether or not there is still a serious question as to whether Big White customers should be paying some or all of those project costs" (T1: 9-10) ("FortisBC Proposal" or "Preliminary Question").

Neither BWSR, nor the B.C. Old Age Pensioners Organization et al. ("BCOAPO"), nor any other party, were opposed to the procedure suggested by FortisBC; however, BCOAPO wanted the opportunity to ask Information Requests about the information already filed (T1:34). BWSR also indicated that, if dealing only with the question put forward by FortisBC, a written process would suffice (T1:73).

Following the Procedural Conference, the Commission Panel issued Order No. G-46-07 (Exhibit A-3) dated April 23, 2007, which established a written process to consider the FortisBC Proposal. The written process allowed for Information Requests by Intervenors and the Commission and responses thereto by FortisBC, and then FortisBC submissions followed by Intervenor submissions and concluding with reply from FortisBC by June 29, 2007.

2.0 THE FORTISBC APPLICATION

In its Application filed March 9, 2007, FortisBC explained that it had retained EES Consulting ("EES") to develop a Cost of Service ("COS") Study to separate the costs and revenues of the Big White area from the rest of the service area, forecast the impact of the Project on the Big White COS and, based on those findings, recommend an appropriate rate design for funding the Project. The EES report titled "Cost of Service Report Related to Big White Service Area, March 2007" ("EES Report") is filed as Appendix "A" to the Application. FortisBC also explained that it had revised the British Columbia Hydro and Power Authority ("BC Hydro") System Extension Test ("SET") that was originally filed on a "best efforts" basis during the CPCN hearing and indicated that it would file the revised SET calculation along with a reconciliation to its original SET prior to the Pre-hearing Conference.

FortisBC serves approximately 1,800 residential and 60 commercial customers in the Big White area (Exhibit B-1, EES Report, p. 3). According to FortisBC, the Big White COS indicates that after the Project has been completed without the Project costs directly assigned to Big White, Big White area customers have been and are paying more than their COS and will continue to do so into the foreseeable future. FortisBC also submitted that:

> "Because capital additions are "lumpy" and are usually built with extra capacity to meet loads that will grow over time, there are continually situations where more is spent on certain customers than on others. The costs to serve a specific customer will fluctuate a great deal over time as capital additions occur and loads change. Over time, it is generally accepted that these capital additions will average out" (Exhibit B-1, p. 2).

Based on the results of the analysis, FortisBC does not recommend that some or all of the customers of the Big White area, as distinct from all FortisBC ratepayers, be required to fund some or all of the costs of the Project and submits that postage stamp rates should be maintained.

The Application also discusses certain implementation and policy issues which, in FortisBC's view, should be addressed prior to any decision to impose a line extension charge, rate surcharge or zonal rates on Big White customers. However, because the Commission Panel, as requested by FortisBC and agreed to by Parties, has limited the question at this time to consideration of the preliminary issue of whether or not there is still a serious question as to "whether Big White customers should be paying some or all of those project costs", the implementation issues were not further addressed.

The EES Report submits that "The pertinent technical question is whether or not the revenues and allocated costs from/to the Big White area are significantly different from those revenues and allocated costs collected from/to other areas within the FortisBC service territory to warrant special and unique retail rate treatment for the Big White area" (Exhibit B-1, EES Report, p. 2).

Using the COS methodology that was prepared by EES for FortisBC and approved by the Commission in 1997, the EES Report developed a COS that separated out the costs and revenues of the Big White area from the rest of the FortisBC service area and examined several different scenarios:

- Case 1 - the base case using the actual revenue requirements and loads for 2006, but without the costs of the Big White project;
- Case 2 - the base case including the costs of the Big White project and loads projected for 2010;
- Case 3 - Case 3 includes "full build-out" of customers at Big White, assumed to occur about 2026. Case 3 also assumed that the average energy usage per customer would be 800 kWh in the months of April through October to reflect a minimum usage consistent with the rest of the FortisBC area (Exhibit B-1, EES study, p. 7).

EES indicated that it also reviewed the impacts of using a different COS methodology recently proposed by BC Hydro and that the difference in results from using the BC Hydro methodology were negligible (Exhibit B-1, EES Report, p. 10).

Revenue to cost ratios reflect the ratio of the revenues collected from a group of customers (often a customer class, in this case a sub-region of the service territory) to the costs associated with service to that group of customers. The revenue to cost ratio results presented in the EES Report are summarized in the table below:

	Project costs allocated to all customers	**Direct Assignment of All Big White Transmission Costs**
Case 1 Big White	113.8%	113.8%
Remaining service area	99.8%	99.8%
Case 2 Big White	116.4%	63.3%
Remaining service area	99.7%	101.1%
Case 3 Big White	122.6%	83.8%
Remaining service area	99.5%	100.6%

The EES Report states that: "Over time, Big White customers will be paying only about 10 percent less of their cost than other residential customers, all other things being equal" (Exhibit B-1, EES Report, p. 12).

To provide some comparative results, EES also applied the same type of COS analysis to three other similarly situated communities in the FortisBC territory, including Osoyoos which, like Big White, is facing a major transmission project. FortisBC confirmed that the transmission facilities related to the Osoyoos project are all radial facilities extending from FortisBC's transmission network and required solely to service existing and increased load in Osoyoos (Exhibit B-5, p. 26). The results of the EES analysis are provided in the table below.

	Revenue to Cost Ratio
Christina Lake	82.1%
Kaslo	128.1%
Osoyoos (with different cases)	
Case 1 - Before expansion cost	113.1%
Case 2 - Direct assignment of new distribution	102.7%
Case 3 - Direct assignment of new transmission and distribution	71.4%

The EES Report comments that "One particular concern would be a scenario where Big White customers pay for the cost of the Big White transmission project through a line extension or surcharge, while at the same time they are required to pay a portion of the Osoyoos transmission project in base rates" (Exhibit B-1, EES Report, p. 13). If Big White customers alone absorb the cost of the Project, the rate impact is expected to be an 84 percent increase in rates to Big White customers. If all customers absorb the costs, the rate impact is approximately 1.0 percent (Exhibit B-2, p. 32; Exhibit B-5, pp. 17-18).

In response to a Commission Information Request, FortisBC also notes that the Kettle Valley Distribution source project, approved by Order No. C-5-06 at an estimated cost of $21.5 million, includes a new substation and transmission system improvements to address reliability and supply problems for the Boundary area, and states that "the relatively small number of customers in the Kettle Valley area did not give rise to a cost recovery mechanism such as that being considered for Big White" (Exhibit B-2, p. 2).

Also in response to a Commission Information Request, FortisBC filed a revised SET calculation to show what contribution would be required from the Big White area if a SET was considered to be an appropriate mechanism on which to base a contribution in the circumstances under review. A further revised SET calculation was subsequently filed (Exhibit B-6, p. 7) which shows that if the transmission and distribution costs are allocated to all customers in the Big White area, the Project generates a net revenue shortfall of approximately $718,000 over 20 years and, if allocated to only new customers in the Big White area, would generate a revenue shortfall of approximately $13.5 million. However, FortisBC states that the SET calculation is not the appropriate test to determine a contribution for the Project and that "Notwithstanding those calculations, the application of generally accepted rate making principles must provide the overriding guidance. It was clearly stated in the Rate Design Application that it is the approved practice for transmission expenditures to be paid for all FortisBC customers" (Exhibit B-5, p. 3).

3.0 SUBMISSIONS OF THE APPLICANT AND INTERVENORS

3.1 FortisBC June 8, 2007 Submission

On June 8, 2007, FortisBC filed its Submission related to the FortisBC Proposal or Preliminary Question identified in Section 1.4 on page 3, namely: "… whether or not there is still a serious question as to whether Big White customers should be paying some or all of those project costs" (T1: 9-10).

FortisBC relies upon new information filed in its Application, particularly the EES Report, and responses to Commission Information Requests to support its position that the Preliminary Question should be answered in the negative.

FortisBC cites the EES Report which states that "In the case of the Big White Project the subject upgrade is a capacity expansion for the entire community and not just one customer. Thus the application of a line extension fee, in this case, is conceptually and philosophically flawed" (FortisBC Submission, p. 4). In FortisBC's view there has been no 'applicant' for the Project and, therefore, the Commission would have to amend the Company's tariff in order to make some or all of the customers in the Big White area pay for the Project. FortisBC does not believe the evidence supports such an amendment to its tariff (FortisBC Submission, p. 3).

FortisBC notes that if the transmission portions of the Project are not directly assigned to Big White, the Big White customers more than cover their cost of service through the entire period examined in the study. The Company states that "Even when the full costs of the Project are directly assigned to Big White customers in the Study, the revenue to cost ratio is over 80 percent once load growth occurs" (FortisBC Submission, p. 5). FortisBC notes that Table 8 of the EES report shows that the revenue to cost ratio for Christina Lake is 82.1 percent and submits that the new information derived as a result of the EES Report was based on generally accepted rate-making principles that support the recommendation that the costs of the Project should be allocated to all customers (FortisBC Submission, pp. 5-6). FortisBC further cites the EES Report, which states it is standard practice to average costs out among customers within a class, despite the fact that they differ in regard to cost to serve (Exhibit B-2, EES Report, p. 18).

The Company also notes that BC Hydro, in response to an Information Request in a current proceeding before the Commission to review the BC Hydro Rate Design Application, stated:

> "BC Hydro considers postage stamp rates to be a fundamental rate design objective….The application of postage stamp rates has been in place for many decades and continues to remain a cornerstone of rate design for BC Hydro. Absent any policy direction from the provincial government it is unlikely that BC Hydro would move away from this fundamental rate design objective. The 2007 Energy Plan does not contain any policy actions specifically encouraging or requiring a move away from postage stamp rates.
>
> BC Hydro notes that the concept of postage stamp rates is practiced by most distribution utilities, as a matter of public policy, and in some jurisdictions is also mandated through legislation."

FortisBC also cites a further response of BC Hydro to an Information Request in the BC Hydro Rate Design proceeding wherein BC Hydro states "… BC Hydro considers that recovering the costs of a system upgrade that serves many customers, whether by means of a contribution or a rate surcharge, would generally be contrary to the principle of postage stamp rates" (FortisBC Submission, p. 6).

FortisBC submits that the SET calculation is not the proper test to apply in order to determine the level of appropriateness of a customer contribution for the Big White Supply Project. Further, the Company submits that in its amended response to the BCOAPO Information Request 1.1 (Exhibit B-6), for the scenario under which all customers of Big White were allocated the full cost of the supply project, the Revenue Shortfall is about 3.5 percent, or $718,000, of the full cost of $20.3 million. "Based on this new information, even if this test were to be applied exclusively to Big White customers, the Company suggests that this is within a plus/minus range for which no contribution should be required" (FortisBC Submission, p.8).

FortisBC submits that the application of generally accepted rate-making principles must provide the overriding guidance and that the revenues and allocated costs from/to the Big White area are not significantly different from those revenues and allocated costs collected from/to other areas within the FortisBC service territory to warrant special and unique retail rate treatment for the Big White area (FortisBC Submission, pp. 8-9).

3.2 BC Old Age Pensioners' Organization et al. Submission

BCOAPO filed its submission on June 21, 2007 and argued that the Preliminary Question must be answered in the affirmative, in part because recent information shows that FortisBC is only proceeding with the Project to meet the needs of new customers. BCOAPO submits that the key issue is not whether FortisBC should maintain postage stamp rates, but whether new customers in Big White should be required to contribute to the cost of a significant upgrade being undertaken solely to meet their future demands for new electricity (BCOAPO Submission, p. 1).

BCOAPO submits that there appears to be a fundamental inconsistency between the treatment of extensions initiated by a formal application from a new customer – in which case existing customers are held harmless through contributions from the applicant in accordance with Schedule 74 of the FortisBC tariff – and extensions initiated as the result of FortisBC forecasts of load growth generally or in a specific area. In this latter circumstance, the costs are borne by existing and future customers (BCOAPO Submission, p. 5).

BCOAPO submits that:

> "… projects involving radial extensions to connect customers served at transmission voltages are usually subject to an extension test and a customer contribution calculation. The rationale is that the costs are being incurred to specifically serve (and benefit) the particular transmission customer. This is apparent in the Special Contracts section of Schedule 74 (see also FortisBC Submissions, p. 7).
>
> In the case of the Big White Project, existing distribution facilities are being upgraded to transmission voltages in order to meet the forecast needs of new customers. The transmission facilities are not part of the Company's overall grid network but rather radial facilities required to service new loads. In this context, the principle appears to be the same whether there is one new transmission customer at the end of the line or a number of new distribution customers…
>
> The fact that the answer depends on whether the line is energized at a transmission or distribution voltage is inconsistent with the overall principle of whether existing customers should pay for costs incurred principally to expand/connect to new customers (BCOAPO Submission, p. 6)."

BCOAPO reviewed the SET test results and submits that the SET calculations provide an appropriate measure of the extent to which existing customers will have to bear the costs of providing service to new customers at Big White (BCOAPO Submission, p. 8). BCOAPO concludes that new customers, as opposed to both existing and new customers, in the Big White area should be required to fund almost all of the costs of the Project.

BCOAPO submits that "there is a need for some additional mechanism to be put in place if the Commission wishes to avoid existing customers, as well as new customers on other parts of FortisBC's system, subsidizing the service to new customers in areas such as Big White". BCOAPO argues that "This approach would avoid setting a precedent allowing for a move away from postage stamp rates, and would not apply to transmission upgrades generally". BCOAPO states that its proposed approach would apply to transmission upgrades that would benefit new customers who would otherwise not pay for any of the costs related to an upgrade made entirely to meet their forecast electricity demands (BCOAPO Submission, p. 10).

Finally, BCOAPO states that between 1976 and 1996, Big White Ski Development Ltd. and Big White customers contributed significantly to the costs of the original extension to the Big White area and suggests that it would be "… ironic if existing customers at Big White were required not only to contribute to the costs of the original power supply to the area, but also to fund the power supply for new customers, while the new customers were not required to contribute at all to the cost of the upgrade that is being undertaken purely to meet their proposed demands" (BCOAPA Submission, p. 10).

3.3 Big White Ski Resort Ltd. Submission

On June 22, 2007, BWSR filed its submission on the Preliminary Question and submitted that the answer is "No". In reaching this conclusion, BWSR submits that the first issue to be considered is whether the postage stamp rates are to remain in effect. BWSR submits that if the Commission finds no reason to depart from "… the longstanding postage stamp system in existence throughout the Province…", then any form of additional contribution from BWSR or Big White ratepayers could only be justified by determining that either Big White ratepayers constitute their own rate class or the Project is a system extension rather than a reinforcement resulting from "organic load growth".

In the view of BWSR no other participant in the proceeding supports a change to the postage stamp system. BWSR also argues that the same argument could have been made by BCOAPO with respect to the Osoyoos upgrade, the Kettle Valley Upgrade and every other expansion of facilities to accommodate increased growth. BWSR submits that "If Big White Ratepayers must pay for these upgrades, other communities will have to pay for their upgrades. Overall the cost will be the same, but some communities will be burdened to such a degree that they will not be able to afford the quality of service they have enjoyed for many years" (BWSR Submission, p. 4). BWSR also draws on the 2002 and 2007 Energy Plans issued by the Province, as well as the remarks at the Procedural Conference by a representative of the Resort Development Division of the Ministry of Tourism, Sport and the Arts ("MTSA"), to argue that the Province has supported and continues to support postage stamp rates.

BWSR also submits that it would be inconsistent and unfair to require Big White ratepayers to pay these costs given the Commission's September 23, 2005 Decision "In the Matter of British Columbia Transmission Corporation Transmission System Capital Plan F2006 to F2015 Application". In that Decision, the Commission approved approximately $15 million of transmission upgrades and substation distribution assets related to the Whistler Village resort area without any requirement for rate revisions or an additional contribution from Whistler ratepayers (BWSR Submission, pp. 5-6).

BWSR cites the evidence of FortisBC that the recovery of costs from Big White ratepayers would be a movement away from postage stamp rates (Exhibit B-2, p. 1) and similar statements by BC Hydro in the context of the concurrent BC Hydro Rate Design proceeding. BWSR submits that if there is to be any change to the postage stamp system, it should come through a generic process, which allows for the input of government, all utilities, communities within the Province, ratepayers and the public (BWSR Submission, p. 8).

BWSR submits that “The evidence provided by Fortis in this proceeding makes it clear that the Big White area has a cost of service entirely in keeping with similar areas, and that there is no cost of service justification to create a new rate class for customers in the Big White area” (BWSR Submission, p. 9).

BWSR submits that neither the *Utilities Commission Act* nor sound rate-making principles allow the Commission to target a specific group of ratepayers for special adverse treatment based on matters that are independent of the cost to serve those customers, and that, to the contrary, such discrimination is prohibited. BWSR states that all of the evidence in this proceeding shows that the Big White area imposes approximately the same costs of service on the Utility as other communities within FortisBC’s service territory (BWSR Submission, p. 10).

BWSR notes that within a given rate-class, it is not a departure from postage stamp rate-making to collect contributions from individual customers that trigger a specific extension, but BWSR suggests that it is clear from the evidence that the Project is not the result of BWSR nor any other identifiable customer in the Big White area seeking or receiving an extension. BWSR concludes that “As such, there can be no basis for directly allocating all or a portion of the Big White Supply Project costs to any customer individually. Equally, there can be no basis to allocate all or a portion of the Big White Supply Project costs to the collective of ratepayers in the Big White area, since they properly form part of a larger rate class…”. BWSR submits that creating a Big White rate class is not justified under the COS evidence of FortisBC, either with or without the Project, and that were a new rate class created for Big White it would require taking into account all of the incremental and decremental costs of serving the Big White area. As an example, BWSR notes that there would be no reason, if such an exercise were undertaken, that the Big White ratepayers should contribute to the costs of the Nk’Mip Project in the Osoyoos area (BWSR Submission, pp. 12-13).

BWSR dismisses evidence surrounding the SET test and states that the Project is not an extension, so a test used to determine incremental cost and their allocations for an extension is irrelevant (BWSR Submission, pp. 13-14).

BWSR summarizes the issue as follows: first, postage stamp rate-making is clearly the policy of the Province and the correct basis for making the decision in this case; second, if postage stamp rate-making is the correct context from which to make this decision, neither BWSR nor the Big White area belong in its own rate class; and third, if postage stamp rates apply and the Big White area is not its own rate class, there is no justification for imposing an incremental cost on the Big White area. BWSR submits that the Commission should conclude that no serious question remains as to whether Big White customers should be paying for some or all of the Project costs (BWSR Submission, pp. 17-18).

3.4 Submissions of Other Intervenors and Interested Parties

Several individuals and organizations intervened in this proceeding. Mr. Wait filed a submission dated June 22, 2007 in which he states that "Big White is not so significantly different from any other community in the FortisBC service area that it should be singled out for special treatment", and that he sees nothing indicating that FortisBC should deviate from its postage stamp approach to rates in regards to the Project (Wait Submission, p. 1).

In its intervention, the MTSA suggested that "any decision affecting operations of BWSR may have implications to other resorts across the province or could place BWSR at a competitive disadvantage" and noted that the "MTSA is responsible for ensuring that the resort is developing consistent with the approved Master Plan and the Master Development Agreement that was signed by the resort and the Province" (Exhibit C5-1). Ms. P. Brown, on behalf of MTSA, stated at the Procedural Conference that there are about 48 resorts in the province and 25 of those would be very similar in nature to Big White (T1:36).

Ms. Slack, in her intervention, stated that she believes in 'postage stamp' rates and that "Big White will be no different than other seasonal influx communities. . ." (Exhibits C2-1, C2-2).

The Commission Panel also received numerous Letters of Comment, almost all in favour of maintaining postage stamp rates (Exhibit E-68) and strongly objecting to the idea of "putting the $20 million expansion onto the small community of Big White" (Exhibit E-4) or being singled out to bear the cost of this Project (Exhibit-7). These comments were received from FortisBC customers both within and outside the Big White area. Many put forward views along the lines that "the Big White Ski Resort is no different from any of the resorts across the Province and any decision to require Big White power users to pay a special levy for this transmission upgrade, could result in serious impacts on the economic intent of the all-seasons resort policy in the Province of B.C." (Exhibits E-19-1, E-56, E-70). Mr. Stannard, in a Letter of Comment dated June 4, 2007 (Exhibit E-14), referred to the comments of Ms. Brown to support the view that Big White is not unique. Others expressed the view that "public utilities and the infrastructure necessary to support them, are by definition, a cost to be borne by the public, not by a specific section of the community" (Exhibit-17) and that the capital costs of the Project "should be an investment by FortisBC and its privately held shareholders" (Exhibits E-18, E-19).

3.5 FortisBC June 28, 2007 Reply Submissions

In its June 28 reply submission, FortisBC states that without new customers new facilities would not be required and that this would be the case with most growth-related projects. The Utility notes that its 2007-2008 Capital Expenditure Plan and System Development Plan Update included $189 million for eighteen growth-related projects and that it has not required any new additional contribution from new customers in any of those growth-related projects. The Company also notes that additional benefits from the Project will accrue to other customers on the FortisBC system than just the Big White customers (FortisBC Reply, pp. 2-3).

FortisBC also submits that BC Hydro's response in its current Rate Design Application proceeding that "recovering the costs of a system upgrade that serves many customers, whether by means of a contribution or a rate surcharge, would generally be contrary to the principle of postage stamp rates" reflects a generally accepted rate-making principle applicable to the Big White Supply Project, and that the facts in the Big White Supply Project do not warrant a deviation from these principles (FortisBC Reply, p. 7).

FortisBC submits that its "… evidence supports the continued use of postage stamp rate-making and results in a conclusion that there is not a serious question that Big White customers should be paying some or all of the Project costs. Based on generally accepted rate-making principles and a consistent practice and application of the Company's extension policy, it is submitted that the Project costs be rolled into rates in keeping with other transmission projects, with recovery from all FortisBC customers" (FortisBC Reply, p. 11).

4.0 COMMISSION DETERMINATION

As noted in Section 1.3 of these Reasons, the Commission in the Reconsideration Decision was not persuaded that a Fully-Allocated Cost of Service study leading to a general consideration of regional rates was required at this time. It was noted that the Project would enhance service to a "… discrete area that appears to be unique insofar as the enhanced service appears to primarily support continued development driven by BWSR". On that basis, the intent of the direction to FortisBC to file a Rate Design Application was clarified; namely, that the Company would make an application to the Commission addressing the two primary questions identified in Section 1.3 above:

1. Should some or all customers of the Big White area, as distinct from all FortisBC ratepayers, be required to fund some or all of the costs of the project?
2. If total funding from all FortisBC ratepayers is not required, then how should the funding from the customers of the Big White area be determined and allocated?

FortisBC filed its Application and, at the subsequent Procedural Conference, noted the new COS information in the Application including the COS study and Information Request responses and, on the basis of that new information, requested a written process to consider a Preliminary Question of "whether or not there is still a serious question as to whether Big White customers should be paying some or all of those project costs".

The COS study shows that currently, before the Project, revenues from the Big White area total approximately 114 percent of its COS. After the Project, if it is rolled into the FortisBC rate base, the revenue to cost ratio is approximately 116 percent as of 2010, the first full operating year of the Project, and approximately 123 percent after 20 years, in 2026. If all of the Project costs are assigned to the Big White area, then the revenue to cost ratio falls to approximately 63 percent in 2010 when the full costs of the Project are incurred but little load growth has occurred, and is approximately 84 percent in 2026. The Commission Panel notes that no party in the proceeding has disputed the methodology used by EES in its COS study.

In the view of the Commission Panel, the COS information and much of the other information to be discussed below, is new information relative to the information available during the CPCN proceeding and to the CPCN Panel and this information supports rolling the costs of the Project into the FortisBC rate base. The COS analysis demonstrates that with the Project costs rolled into the FortisBC rate base, the Big White area will be covering between 116 percent to 123 percent of the costs associated with the area. Even with the Project costs assigned directly to the Big White area, the revenue to cost ratio is approximately 84 percent after load growth has occurred. The Commission Panel agrees with FortisBC that all of these results fall within the range of revenue to cost ratios of the other communities in the FortisBC area that were analyzed and notes that the EES Report (p. 13) suggests that the entire FortisBC service area would face a similar variability between areas and towns.

Moreover, rolling the Project costs into rate base would be consistent with the Commission approval of the British Columbia Transmission Corporation Whistler reinforcement project without any requirement for any rate revisions or contributions from Whistler ratepayers.

The Commission Panel, therefore, agrees with FortisBC that an analysis of the revenues and allocated costs indicates that Big White is not sufficiently different from other areas in FortisBC’s service territory to warrant special and unique retail rate treatment. The Commission notes that comparable transmission upgrades for other communities have been undertaken and have not attracted special rates or funding requirements, including the Whistler project and the FortisBC Nk’Mip project in the Osoyoos area.

FortisBC and BWSR both noted the BC Hydro evidence in the concurrent BC Hydro Rate Design proceeding that it considers postage stamp rates to be “… a cornerstone of rate design for BC Hydro…” that without a policy direction from the provincial government, BC Hydro would be unlikely to move away from this fundamental rate design objective; and that BC Hydro considers recovering the costs of a system upgrade that serves many customers, whether by means of a contribution or a rate surcharge, to be contrary to the principle of postage stamp rates. While the Commission Panel gives little weight to this position of a non-party which has been filed in another ongoing proceeding, the Commission Panel does agree with FortisBC and BWSR that the facts of this case do not warrant a deviation from FortisBC's past practice.

The Commission Panel agrees with FortisBC and BWSR that the Project is not an extension. As stated in the EES Report, "…in this case, the Company's extension policy should not apply to the project because it is not an Extension as defined under the tariff, there is no Applicant applying for the project as defined under the tariff, and the project is primarily around a transmission line and substation not a distribution extension." As BWSR has submitted, the Project is more properly characterized as a load growth project given that it is not the result of any single customer seeking new service. Therefore, the Commission Panel finds that a test used to determine incremental costs and their allocations for an extension, such as BC Hydro's SET, or a new SET, is not particularly relevant and should not be retroactively imposed for the Project.

BCOAPO argues that whether talking about transmission or distribution facilities or whether it is one applicant or multiple new customers, the same question exists as to whether existing customers will be required to contribute to the costs of connecting new customers and whether existing customers in the Big White area and its service on the Fortis BC system will be unfairly burdened by these expenditures (BCOAPO Submission, p. 6).

BCOAPO acknowledges FortisBC's position that there are widespread benefits from the Project including reduced line losses and improved reliability, however, BCOAPO maintains that improved reliability may not be something that FortisBC would have invested in just for existing customers. In the Commission Panel's view, the fact remains that there are benefits that will accrue to existing Big White customers and other customers on the FortisBC system as a result of this Project (BCOAPO Submission, p. 8). Furthermore, the Commission considers that spreading Project expenditures amongst all FortisBC customers will not unfairly burden existing customers because, over time, contributions to Project costs by non-Big White area customers of FortisBC will be offset to some extent by contributions to non-Big White reinforcement projects by Big White area customers. As noted in the EES Report, "The costs to serve a specific customer will fluctuate a great deal over time as capital additions occur and loads change. Over time, it is generally accepted that these capital additions will average out" (Exhibit B-1, EES Report, p. 3).

The Commission Panel is not persuaded by BCOAPO's submission that there should be a mechanism developed with which to collect a contribution from new Big White customers. BCOAPO notes that, in the early years of Big White, the developer and Big White customers contributed significantly to the costs of the original extension to the Big White area and that it would be "… ironic if existing customers at Big White were required not only to contribute to the costs of the original power supply to the area, but also to fund the power supply for new customers, while the new customers were not required to contribute at all to the cost of the upgrade that is being undertaken purely to meet their proposed demands" (BCOAPA Submission, p. 10).

BCOAPO's proposed solution is to require only new Big White customers to contribute to the Project costs. BCOAPO suggests that its proposed solution would apply to transmission upgrades that will benefit new customers who would otherwise not end up paying for any of the costs related to an upgrade made entirely to meet their forecast electricity demands (BCOAPO Submission, p. 10). The Commission Panel notes, however, FortisBC's submission that by applying the existing rate structure, new customers at Big White will pay a share of common costs for the substation and transmission costs for the rest of the service area and that it would not be fair for new customers at Big White to pay 100 percent of the Big White Supply Project and also have to pay a share of similar growth related transmission and substation costs for the rest of the Company. The Commission Panel agrees.

The Commission Panel is sympathetic to BCOAPO's argument that FortisBC appears to rely on a strict, technical interpretation of its tariff and to BCOAPO's suggestion that if existing guidelines and tariffs are not adequate to resolve the issue of new customer contributions to the cost of the Project, then the Commission should establish a process to develop such a framework and that past practice and application of the policy should not be a barrier to doing things correctly in the future (BCOAPO Submission, pp. 4, 5 and 9). However, the Commission Panel considers that the circumstances in a given case should be demonstrated to be appropriate and justified to warrant a departure from a long history of interpretation and past practice and before changes are considered. The Commission Panel considers that to be meaningful and workable, it does make sense that there should be an 'applicant' to whom the tariff can readily and easily apply. The Commission Panel is not persuaded that this is the case here. The Commission Panel, therefore, agrees that in the circumstances before it, the provisions of the current FortisBC extension policy and retail tariffs should apply to all Big White customers, as they have to other FortisBC customers.

The Commission Panel notes the statements made by Ms. P. Brown on behalf of the MTSA and agrees that the Big White Ski Resort, and specifically this Project, in many respects on the evidence before this Panel, does not appear to be unique, at least not to a sufficient extent to warrant separate and unique rate treatment.

As discussed above, there was insufficient information on the record of the prior CPCN proceeding to address the issue raised related to whether the Project and area which it would serve "is sufficiently unique that it should not be considered a community in the same sense as many other communities in the FortisBC area". Based on the information filed in this proceeding, and after carefully reviewing and considering the views expressed and the submissions of parties and those who have filed comments, the Commission Panel is persuaded that neither Big White nor the Project are sufficiently unique to warrant different rate treatment.

The Commission Panel determines that the new evidence and submissions provided in this proceeding support including the costs of the Project in the FortisBC rate base, with no additional contribution required from the BWSR or Big White ratepayers, new or existing. That determination answers the Preliminary Question in the negative, as suggested by FortisBC, BWSR and many others, and effectively answers the first question posed in the CPCN Decision and Reconsideration Decision, hereby rendering academic or moot a response to the second question and making it unnecessary to continue the proceeding on this matter and the proceeding is hereby concluded.

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

FortisBC Inc.

2009 Rate Design and Cost of Service Analysis

DECISION

October 19, 2010

Before:

A.J. Pullman, Panel Chair/Commissioner
L.A. O'Hara, Commissioner
M.R. Harle, Commissioner

BCMEU view that the Demand Limit provisions essentially set the nameplate capacity of the substation and rejects Mr. Saleba's arguments in support of 100 percent ratchet. **Accordingly, the Commission Panel directs FortisBC to set the billing determinants for the Wholesale Customers to be consistent with those to be set for the Large General Service Transmission Customers.**

With regard to the specific Celgar rate schedule matters, the Commission Panel finds that under the current circumstances Celgar is ineligible to take service under RS 33 and directs FortisBC to provide Celgar service under RS 31 effective January 2, 2011. This ineligibility is primarily due to the following:

- there is no current signed agreement as stipulated by the Electric Tariff, RS 33; and
- FortisBC has failed to explain how the current low load factor could qualify as "satisfactory" as stipulated by the Electric Tariff.

Based on evidence and determinations related to Celgar, as addressed in Sections 2.0 and 6.0, the Commission Panel also recommend that FortisBC and Celgar reconsider the options available for designing a practical and workable rate schedule for Celgar. *For instance, a stand-by rate similar to* that offered by BC Hydro might still be an option regardless of the submissions made during the Oral Phase of Argument.

3.4 Postage Stamp Rates

3.4.1 General Policy

The concept of postage stamp rates refers to the practice of charging every customer within each class of service the same rate, regardless of the geographical region in the province in which service is provided, even though this may entail some cross-subsidies between customers in a class. In British Columbia, in addition to FortisBC, BC Hydro and a few municipal and small private utilities also distribute electricity. Accordingly, the entire Province is not covered by postage stamp rates for electricity.

3.4.2 Positions of Parties

FortisBC states it considered and consulted on seasonal rates and urban/rural rates, but rejected these options since it felt they were unduly discriminatory to electric heat customers (in the case of seasonal rates) or rural customers (in the case of urban/rural rates) (Exhibit B-1, p. 55).

Mr. Shadrack questioned the postage stamp principle for allocating transmission and distribution costs. He pointed to FortisBC evidence that North Okanagan's percentage share of the total load will increase by 20.8 percent while Kootenay's share is forecast to decline by a further 20.4 percent. He asks: "Why ... should all classes of West Kootenay customers participate in paying for purchase of wheeling from BCTC for customers in the Okanagan and Creston?" (Exhibit C2-10).

At the request of the Commission Panel, Commission Counsel filed a 2003 letter from the Minister of Energy, Mines and Petroleum Resources to the President of the Union of British Columbia Municipalities indicating his support for postage stamp rates:

> *"Electricity rates will be set on a postage stamp basis. This means all customers within a particular customer class will receive the same rate, regardless of their location in the Province."* (Exhibit A2-1)

FortisBC acknowledges that there may be some inequity in having one single rate but believes that the continuation of the postage stamp rate provides an overall benefit to customers. FortisBC submits the following key reasons to support its position:

- postage stamp rates reduce the price fluctuations that would otherwise occur for regional subgroups due to new regional infrastructure projects and, therefore, the cost impediments to growth in rural areas and/or areas needing infrastructure; and
- postage stamp rates take into account the fact that although high density customers are generally less expensive to serve, they also generally receive higher levels of service, particularly with respect to reliability, whereas low density customers are generally more expensive to serve but may receive lower levels of service.

(FortisBC Argument, pp. 55-56)

Commission Determination

The Commission Panel notes that while regional rates may have some merit, more detailed, regionally distinguished cost of service studies would be required for a proper analysis. Accordingly, the Commission Panel concludes that it has insufficient evidence to justify a departure from the current postage stamp principle followed by FortisBC, which is also supported by current government policy.

The Commission Panel further notes that the current policy, supporting same rates to all members of a customer class regardless of their location in the Province, can also be interpreted to support the idea that the FortisBC residential customer rate structure should more closely resemble the BC Hydro residential rate structure.

Newfoundland
& Labrador

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF THE

2003 GENERAL RATE APPLICATION

FILED BY

NEWFOUNDLAND AND LABRADOR HYDRO

DECISION AND ORDER

OF THE BOARD

ORDER No. P.U. 14 (2004)

BEFORE:

Mr. Robert Noseworthy
Chair and Chief Executive Officer

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

Mr. G. Fred Saunders
Commissioner

P.U. 14 (2004)

IN THE MATTER OF the *Electrical Power Control Act* R.S.N. 1994, Chapter E-5.1 (the "*EPCA*") and the matter of the *Public Utilities Act* R.S.N. 1990, Chapter P-47 (the *"Act"*)*;*

AND IN THE MATTER OF an application by Newfoundland and Labrador Hydro for approval of, *inter alia*, rates to be charged its customers (the "*Application*").

BEFORE:

Robert Noseworthy
Chair and Chief Executive Officer

Darlene Whalen, P.Eng.
Vice-Chair

G. Fred Saunders
Commissioner

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PART ONE. PROCEDURAL MATTERS AND BACKGROUND

I. APPLICATION AND HEARING

1. The Application

Newfoundland and Labrador Hydro (NLH) filed an Application (Appendix A) with the Board of Commissioners of Public Utilities (the "Board") on May 21, 2003 for an Order of the Board approving, among other things, the rates to be charged, as of January 1, 2004, for the supply of power and energy to its Customers.

On August 12, 2003 NLH filed an amended Application (Appendix B) to reflect:

1) certain directions by Government pursuant to Section 5.1 of the *EPCA*, 1994;
2) a reduction in the requested rate of return on equity for rate setting purposes to 9.75%; and
3) Board Order No. P. U. 23(2003), approving revised rates for Newfoundland Power (NP) customers, which flow through to NLH rural customers.

The Pre-filed Evidence, Exhibits and Studies filed as part of the original application were also updated and re-filed with the amended Application.

In its Application NLH is proposing the following:

(1) "that the rate charged NP be increased, no later than January 1, 2004, to 54.45 mills per kWh;
(2) that the rate charged NP as of January 1, 2004, for firming up secondary energy purchased from Corner Brook Pulp and Paper Limited and re-sold to NP as firm energy be decreased to 6.41 mills per kWh;
(3) that the rates charged to Industrial Customers for firm service be increased, no later than January 1, 2004, to a demand charge of $6.49 per kW per month, an energy charge of 27.55 mills per kWh and the relevant annual specifically assigned charges;
(4) that the rates charged to Industrial Customers for non-firm service be, as of January 1, 2004, $1.50 per kW per month and a variable energy charge based on the calculation on the Rates Schedules attached to the Application;
(5) that the rate for wheeling energy for Abitibi-Consolidated Company of Canada be decreased to 4.49 mills per kWh as of January 1, 2004;
(6) that the existing policy be continued of allowing NLH, as NP changes its rates, to automatically adjust the rates which it charges its Island Interconnected Rural Customers, its customers served from the L'Anse au Loup System, and its non-Government Isolated Domestic Rural Customers for the first 700 kWh per month of consumption, so that rates are the same as the rates charged by NP to its customers;
(7) that the existing policy be continued of allowing NLH to change the rates charged for consumption over 700 kWh per month of electricity sold to non-Government Isolated Domestic Rural Customers (the "lifeline block") by the average rate of change (i.e. increase or decrease) granted to NP from time to time;

(8) that the policy, outlined in Order No. P .U. 7(2002-2003) of charging rates based on full cost recovery for Government departments, excluding hospitals and schools in Isolated Rural Systems, be continued;

(9) that the lifeline block be phased out for Isolated General Service Customers and that a demand energy rate structure be implemented for these customers as directed by Order No. P. U. 7(2002-2003) and phased in over a five-year period;

(10) that the rates for Labrador Interconnected Customers be based on a uniform Rate Structure as approved in Order No. P. U. 7(2002-2003) and phased in over a five-year period;

(11) that the following financial targets be approved by the Board as appropriate for NLH:

Return on Equity (ROE)	*9.75%*
Debt to Capital Structure	*80%*
Return on Rate Base	*8.15%*

(12) that the estimated 2004 average Rate Base be $1,485,468,000;

(13) that the just and reasonable Rate of Return on the estimated average Rate Base for 2004 be 8.15%; and

(14) certain minor amendments to the Rates, Rules and Regulations which govern the provision of service to Rural Customers be made to eliminate the statement preparation fee; to reduce the fee applicable for customer name changes from $14 to $8; and to extend the application of the reconnection fee to circumstances where customers request reconnection of service following a request for a landlord to disconnect."

On October 31, 2003 NLH updated the data filed with its Application to reflect more current information. The revised information filed included actual expenses to August 31, 2003, and the most recent forecast for relevant matters such as No. 6 fuel price, load, interest rate and exchange rates.

Based on NLH's updated filing the base rate increase to NP as a result of the Application was projected to be 12%, resulting in a projected increase to the end consumer of approximately 6.5% as of January 1, 2004. The increase in base rates for Island Industrial Customers was forecast to be 12.2% as of January 1, 2004.

2. Notice and Pre-Hearing Conference

Notice of the Application and Pre-hearing Conference was published in newspapers throughout the Province beginning on June 9, 2003. The Pre-hearing Conference was held on July 18, 2003. The Board issued Procedural Order No. P. U. 24(2003) on July 23, 2003 which identified registered intervenors, set procedural rules for the conduct of the hearing, and set the schedule for the filing and service of documents, the motions days and the hearing. (Appendix D)

Registered intervenors for the proceeding were:

1) Government appointed Consumer Advocate (CA), Mr. Dennis Browne, Q.C.; and Counsel, Stephen Fitzgerald, LL.B.
2) Newfoundland Power Inc. (NP), represented by Mr. Ian Kelly, Q.C. and Mr. Brock Myles, LL.B.

3) NLH's Industrial Customers (IC), namely Corner Brook Pulp and Paper Limited, Abitibi Consolidated Company of Canada – Stephenville and Grand Falls Divisions, North Atlantic Refining Limited and Voisey's Bay Nickel Company Limited; represented by Mr. Joseph Hutchings, Q.C. and Mr. Colm Seviour, LL.B.
4) the Towns of Labrador City and Wabush, represented by Mr. Edward Hearn, Q.C.

NLH was represented throughout the hearing by Ms. Maureen P. Greene, Q.C., and Mr. Geoffrey P. Young, LL.B. The Board notes that Counsel for the Towns of Labrador City and Wabush was not present for every day of the hearing. As stated by their Counsel in final submissions, the interest of the Towns of Labrador City and Wabush was a particular one that did not require attendance at the hearing when issues peripheral to their interests were being addressed.

The Board was assisted at the hearing by Mr. Mark Kennedy, LL.B., who acted as Board Hearing Counsel; Ms. Dwanda Newman, LL.B., Board Counsel; Ms. Cheryl Blundon, Board Secretary; and Ms. Barbara Thistle, Assistant Board Secretary.

3. Motions

On June 25, 2003 the Town of Labrador City filed a notice of intervention and submission requesting, among other things, that it be granted its costs of intervention. NP and NLH filed replies to this motion. At the Pre-hearing Conference the Board heard representations on the motion. The Board subsequently issued Order No. P. U. 25(2003) denying the motion and ordering that the issue of costs would be addressed at the conclusion of the proceeding if a motion for costs was made at that time pursuant to Section 90(1) of the *Act*. (Appendix F)

On September 5, 2003 the IC filed a motion with the Board seeking an order that the expert reports proposed to be filed by Board Hearing Counsel be excluded from evidence substantially on the basis that the filing of such reports raised an apprehension of bias. NLH and NP filed written responses to the motion. The Board heard from the parties on the motion on September 16, 2003 and subsequently issued Order No. P. U. 32(2003) denying the motion. (Appendix G)

The Board was scheduled to convene in Labrador City beginning on November 3, 2003 to hear evidence and public presentations relating to NLH's proposals for the Labrador Interconnected System. On October 29, 2003 the Board received a motion from the Towns of Labrador City and Wabush requesting that the hearings be rescheduled to a later date to allow time to review revised evidence NLH was proposing to file on October 31, 2003. On October 30, 2003 the Board issued Order No. P. U. 34(2003) granting the motion to postpone the Labrador City proceedings. (Appendix I)

4. The Hearing

The hearing commenced on October 6, 2003 and continued over a 10-week period for 35 hearing days. Written submissions were submitted by NLH, the registered intervenors and Board Hearing Counsel on January 12, 2004. Final oral submissions were presented on January 16, 2004. During the hearing the following witnesses testified:

Witnesses called by NLH:

Mr. William E. Wells	President and Chief Executive Officer, NLH
Mr. John C. Roberts, CA	Vice-President, Finance and Chief Financial Officer, NLH
Mr. James R. Haynes, P. Eng.	Vice-President, Production, NLH
Mr. Fred H. Martin, P. Eng.	Vice-President, Transmission and Rural Operations, NLH
Mr. Sam D. Banfield, P. Eng.	Director, Customer Service, NLH
Mr. Robert D. Greneman, P.E.	Associate Director, Stone &Webster Management Consultants, Inc., New York, NY
Ms. Kathleen C. McShane	Senior Vice-President and Senior Consultant, Foster Associates, Inc., Bethesda, Maryland
Ms. Susan Richter, P.Eng.	Senior Hydrotechnical Engineer, SGE Acres Limited St. John’s, NL

Witnesses called by the Consumer Advocate:

Mr. Douglas Bowman	Executive Consultant, KEMA Consulting, Fairfax, Virginia
Dr. Basil Kalymon	Professor of Finance, Richard Ivey School of Business, University of Western Ontario, London, ON

Witnesses called by NP:

Mr. Larry Brockman	President, Brockman Consulting, Atlanta, Georgia
Mr. Barry Perry, CA	Vice-President and Chief Financial Officer, NP
Mr. Lorne Henderson, P. Eng.	Director, Rates & Operations, NP

Witnesses called by the IC:

Mr. Cameron Osler	President and Senior Consultant, InterGroup Consultants, Ltd., Winnipeg, MB
Mr. Patrick Bowman	Consultant, InterGroup Consultants, Ltd., Winnipeg, MB
Mr. Mel Dean	Continuous Improvement Manager, Abitibi-Consolidated Company of Canada Stephenville Mill, Stephenville, NL
Mr. Jean Francois Guillot	General Manager, Abitibi-Consolidated Company of Canada, Stephenville Mill, Stephenville, NL

Witness called by the Towns of Labrador City and Wabush:

Mr. Mark Drazen	Consultant, Drazen Consulting Group, Calgary, AB

Witnesses called by Board Hearing Counsel:

Ms. Gail Tabone	Vice-President, EES Consulting, Kirkland, Washington
Mr. Nigel Chymko	Vice-President, EES Consulting, Calgary, AB
Dr. Leonard Waverman	Special Advisor, National Economic Research Associates (NERA), London, UK
Mr. William R. Brushett, FCA	Partner, Grant Thornton LLP, St. John's, NL (Board's Financial Consultant)

Public participation days were held in Stephenville, Corner Brook, Labrador City, Happy Valley-Goose Bay and St. John's. During this phase of the hearing interested persons and organizations were offered the opportunity to present their views on issues arising from the Application.

The Board heard from the following persons during the public participation days:

In Stephenville on November 24, 2003:

Mr. Mike Tobin, Counsellor, Town of Stephenville and Chairperson, Stephenville Economic Development Committee, Stephenville, NL
Mr. Cator Best, Deputy Mayor, Town of Kippens, Kippens, NL
Mr. Paul Gallant, Bay St. George Chamber of Commerce, Bay St. George, NL
Mr. John MacPherson, Executive Director, Long Range Regional Economic Development Board, Stephenville, NL
Mr. Jim Hickman, President, Local Union 1093, Communications, Energy and Paper Workers Union of Canada, Abitibi Consolidated Mill, Stephenville, NL
Mr. Russell Tulk, President, Santa Maria Club, Knights of Columbus, Stephenville, NL

In Corner Brook on November 25, 2003:

Ms. Priscilla Boutcher, Mayor, City of Corner Brook, Corner Brook, NL
Mr. Terry Locke, Chairman, Great Humber Joint Council, Corner Brook, NL
Mr. Perry Bingle, Executive Director, Humber Economic Development Board, Corner Brook, NL
Mr. Mark Baldwin, President, Greater Corner Brook Board of Trade, Corner Brook, NL
Mr. Jeff Burt, Chairperson, Corner Brook Downtown Business Association, Corner Brook, NL
Mr. Brendan Mitchell, Employee, Corner Brook Pulp and Paper Limited, Corner Brook, NL
Mr. Keith Cormier, Chairperson, Corner Brook Economic Development Corporation, Corner Brook, NL

Ms. Joy Blackwood, Researcher and Recording Secretary,
Corner Brook Port Corporation, Corner Brook, NL
Mr. Matt Organ, Branch Manager, Kinecor Inc., Corner Brook, NL
Mr. Greg Barnes, Area Manager, Clarke Transport, Corner Brook, NL
Mr. Michael Lacey, Employee, Corner Brook Pulp and Paper Limited, Corner Brook, NL
Mr. Eugene Mercier, Employee, Corner Brook Pulp and Paper Limited,
Corner Brook, NL
Mr. Israel Hann, Private Citizen, Corner Brook, NL

In Labrador City on November 26, 2003

Mr. Dave Porter, Vice-President, Human Resources, Iron Ore Company of Canada,
Labrador City, NL
Mr. John McGrath, Director of Human Resources, Wabush Mines, Wabush, NL
Mr. Matt Simpson, Iron Ore Company of Canada, Labrador City, NL
Mr. Graham Letto, Mayor, Town of Labrador City, Labrador City, NL
Mr. Jim Farrell, Mayor, Town of Wabush, Wabush, NL
Mr. George Kean, President, United Steelworkers Local 5795,
Iron Ore Company of Canada, Labrador City, NL
Mr. Tom Kent, Vice-President, United Steelworkers Local 6285, Wabush Mines, Wabush, NL
Mr. Jody Kelly and Mr. Elmo Bingle, Hyron Board and the Labrador West Chamber of Commerce, Labrador West, NL
Mr. Ern Condon, Private Citizen, Labrador West, NL
Ms. Shirley Squires, Private Citizen, Labrador West, NL
Mr. Ray Erger, Owner, Kentech Computers; Employee, Iron Ore Company of Canada,
2nd Vice-President, Labrador City Chamber of Commerce and a member of Ground Search and Rescue, Labrador City, NL.

In Happy Valley-Goose Bay on November 27, 2003:

Mr. Dennis Peck, Director of Economic Development,
Town of Happy Valley-Goose Bay, Happy Valley-Goose Bay, NL
Ms. Carol Best, Central Labrador Economic Development Board, Labrador, NL
Mr. Jamie Snook, Combined Councils of Labrador, Labrador, NL
Mr. Gary Bolger, Mayor, Town of St. Lewis and an Executive Director, Combined Councils of Labrador (Presentation on behalf of the Towns of St. Lewis and Charlottetown, NL)
Ms. Betty Sampson, Town Clerk, Town of Port Hope Simpson, Port Hope Simpson, NL
Ms. Nina Pye, Mayor, Town of Mary's Harbour, Mary's Harbour, NL
Ms. Yvonne Jones, MHA, Cartwright-L'Anse au Clair, NL
Mr. Tony Woolfrey, Deputy Mayor, Town of Rigolet, Rigolet, NL
Mr. Leroy Metcalf, representing the Labrador Inuit Association, Labrador, NL
Mr. Glenn Sheppard, Mayor, Town of Postville, Postville, NL

<u>In St. John's on December 8, 2003:</u>

Mr. Maurice Tuff, B.Eng., President and CEO, Blue Line Innovations Inc., St. John's, NL
Mr. Danny Tuff, Vice-President, Marketing & Business Communications, Blue Line Innovations Inc., St. John's, NL

The Board appreciates the time and effort taken by those who appeared before the Board. The presentations and comments were very helpful in providing the Board with both personal and community perspectives and the Board has considered this input in making its decisions.

Interested persons and organizations were also given the opportunity to submit a Letter of Comment, which also formed part of the record before the Board. The Board also extends its appreciation to those persons and organizations submitting Letters of Comment. Letters of Comment were submitted by:

Mr. Newman Sinnicks, Hawke's Bay, NL
Ms. Doris Randell, Town Clerk/Manager, Town of Englee, Englee, NL
Mr. Allister J. Hann, Mayor, Town of Burgeo, Burgeo, NL
Ms. Mary Sillett, Mayor, Town Council of Hopedale, Hopedale, NL
Mr. Henry Broomfield, Mayor, Town Council of Nain, Nain, NL
Mr. Dave Denine, Mayor, City of Mount Pearl, Mount Pearl, NL
Ms. Phyllis Randell, Town Clerk, Town of Bide Arm, Bide Arm, NL
Mr. Stan Cook, Jr., President, Hospitality Newfoundland and Labrador, St. John's, NL
Mr. Cyril Taylor, Mayor, Town of Raleigh, Raleigh, NL
Mr. Brian Barry, President, Exploits Regional Chamber of Commerce, Grand Falls-Windsor, NL
Mr. Jim Goudie, Vice-President, Deer Lake Chamber of Commerce, Deer Lake, NL
Ms. Gloria Byrne, Corner Brook, NL
Mr. Ray Dillon, Director of Sales, Group Telecom, St. John's, NL
Ms. B. Knight, Labrador
The Town of St. Anthony, St. Anthony, NL
Mr. Neil Cleary, St. John's, NL
Mr. Herbert Brett, President, Newfoundland and Labrador Federation of Municipalities, St. John's, NL

In addition to witness testimony, public presentations and letters of comment, evidence was entered by way of information requests, consent filings, and information filings. The Board has considered all the evidence before it in this proceeding and will refer directly to the evidence in making its findings.

II. PRELIMINARY MATTERS

1. Government Direction

Pursuant to Section 5.1 of the *EPCA* the Lieutenant-Governor in Council (LGIC) is empowered to give directions respecting the policies and procedures to be implemented by the Board in determining rate structures for public utilities. This provision details some of the specific issues upon which a direction can be made, including the setting and subsidization of rural rates as well as the setting of a debt-equity ratio and rate of return for NLH. Pursuant to Section 5.2 of the *EPCA* and Section 4.1 of the *Act* the LGIC is empowered to exempt a utility from both *Acts* when it is in the best interests of the Province as a matter of public convenience or general policy.

Government's statutory power to direct, which has been exercised sparingly since its introduction became important in this hearing with the issuance of several directions to the Board in 2003. The following directions/exemptions were entered on the record in this matter as Information #1 (Appendix C):

- A direction to the Board with respect to the rates charged by NLH, including preferential rates, rural rates and rate changes generally;
- A direction to the Board to hold a hearing into the appropriate rate calculation methodology for the Labrador Interconnected System upon receipt of a complaint of discriminatory rates; and
- An exemption of the Wind Power Demonstration Project from the authority of the Board.
- A direction to ensure recovery in the rates of a utility of the costs of projects exempted from the provisions of the *Act* or the *EPCA* with the exception of the Lower Churchill Development Project.

The direction to the Board to ensure recovery in rates of the costs of exempted projects allows NLH to recover its costs without the oversight of the Board. With respect to the Application, exemptions authorized through Orders-in-Council in 2000 directed recovery in the rates of the costs associated with the following projects: (i) the Granite Canal Project; and (ii) the two power purchase agreements with Abitibi Consolidated of Canada, as agent for the Exploits River Hydro Partnership, and with Corner Brook Pulp and Paper Limited.

These directions were made with clear statutory authority and there was no challenge or argument from the parties as to the way in which these directions should be interpreted or reflected. The Board has accepted these directions as circumscribing its jurisdiction. The Board has reflected these directions in this Decision and Order and, where appropriate, has referenced the relevant direction in its analysis.

2. Complaint by the Towns of Labrador City and Wabush

One of the Government directives required that the Board hold a hearing with respect to the rate calculation methodology for the Labrador Interconnected System upon receipt of a complaint of discriminatory rates. On July 23, 2003 the Towns of Labrador City and Wabush filed a complaint with the Board concerning NLH's rate proposals for the Labrador Interconnected System. (Appendix E) The complaint alleged that NLH's proposed rates for Labrador West are discriminatory and requested that the Board conduct a hearing into the appropriate rate calculation methodology for the Labrador Interconnected System.

Beginning on September 20, 2003 the Board published notice of the complaint advising that the Board would convene in Labrador West to hear evidence with respect to the complaint. Consistent with the terms of the direction of the LGIC, the Board heard evidence and submissions relating to the complaint in Labrador City, Happy Valley-Goose Bay and St. John's. The Board has considered this evidence as well as the submissions of the parties in this Decision and Order.

3. Technical Conference/Mediation

Prior to the start of the hearing the Board set aside a number of days to allow for a technical conference. The purpose of the technical conference was to provide the parties with an opportunity to come to a consensus on certain issues in advance of the hearing. With the assistance of a Board appointed mediator, Dr. J. W. Wilson, the parties focused on cost of service allocation, rate structure and tariff matters.

The Board appointed mediator subsequently prepared a Mediation Report (Appendix H) detailing issues upon which there was consensus as well as those issues where there was no consensus. The parties consented to the filing of this report and the admission of all pre-filed evidence and exhibits of witnesses pertaining to the consensus issues without the calling of witnesses for the purpose of cross-examination.

The Board accepts the Mediation Report as reflecting the consensus of the parties. As contemplated in the Mediation Report the Board will review the evidence filed with respect to each issue, including pre-filed evidence and exhibits, in addition to the consensus set out in the report. In this Decision and Order, the Board has considered the consensus of the parties and the evidence that was filed and, where it determines that it is appropriate, has reflected the consensus in its findings. The issues set out in the Mediation Report are addressed specifically in the relevant section of this Decision and Order.

4. Settlement Agreement

Following the technical conference/mediation process NLH, NP, the CA and the IC held settlement discussions in relation to certain amendments to the Rate Stabilization Plan (RSP). The Towns of Labrador City and Wabush, whose rates are not subject to the RSP, did not participate in the settlement discussions. These discussions, while arising out of the technical conference process, were undertaken without the benefit of a Board appointed mediator and did not involve Board staff or Board counsel. On November 13, 2003 NLH filed as Consent #2 and Consent # 3 proposed amendments to the RSP which were intended to be effective on January 1, 2004. The participating parties consented to the filing of the proposal except that the IC took no position with respect to the amendments of the provisions with respect to the recovery of the plan balances. On December 15, 2003 the Board accepted the proposals in Order No. P. U. 40(2003) ordering that the proposed amendments to the RSP be put in place as of January 1, 2004. (Appendix J)

III REGULATORY UPDATE

1. Progress in Regulating NLH

In Order No. P. U. 7(2002-2003) the Board noted the related application represented NLH's first general rate review in ten years and its first as a fully regulated utility. The Board indicated that the application presented a host of regulatory challenges impacting a variety of stakeholders, including consumers of electricity, Government, and NLH. The Board acknowledged it would take time to address all such challenges and lay the groundwork for the effective regulation of NLH into the future. In Order No. P. U. 7(2002-2003) the Board identified a number of strategic considerations designed to establish appropriate regulatory objectives both for the 2001 general rate application and looking ahead. These strategic considerations were:

- Regulatory Framework;
- Public Policy Considerations;
- Pace of Regulation;
- Decision Criteria; and
- Focus for the Future.

In implementing an effective regulatory regime for NLH the Board is encouraged by progress respecting these considerations, as indicated below.

Regulatory Framework

As NLH's 2001 general rate application was its first as a fully regulated utility, the Board outlined in Order No. P. U. 7(2002-2003) a framework for guiding the regulation of NLH. This regulatory framework was consistent with that applied to NP, the other fully regulated utility operating in the Province. This framework was also detailed in Order No. P. U. 19(2003) arising from NP's latest general rate application and is again recited in this Decision and Order. The framework includes the statutory powers of the Board, jurisprudence, established Board procedures, regulatory principles and description of the ratemaking process. The Board believes a stable, consistent and efficient regulatory framework is important to sound regulation. Following the experience in this NLH's second application as a fully regulated utility, the Board sees no compelling reason why this framework should not continue to apply in regulating both NLH and NP. In this way both utilities will have a proven, predictable and consistent regulatory environment within which to operate. The Board acknowledges changes in this framework may be necessary from time to time, triggered by either legislative imperatives and/or Board initiatives.

Public Policy Considerations

Public policy considerations created a dilemma for the Board in NLH's first general rate application as a fully regulated utility in 2001. The Energy Policy Review initiated by Government in 1998 remained unresolved and numerous other public policy issues were identified impacting the regulatory decisions of the Board. These included the level of cross-subsidization applied to rural rates, the implications on NLH's capital structure of dividends paid to Government, and preferential electricity rates afforded selected customers located in communities served by isolated diesel systems. In this Application Government has directed the Board on a number of matters concerning rural and preferential rates. The Board notes, despite meetings with Government and submission of discussion papers, the evidentiary record ordered by the Board in Order No. P. U. 7(2002-2003) indicated NLH received no response from Government on either the rural deficit or a supportive dividend policy/capital structure. While additional consultation has occurred on the Energy Policy Review since Order No. P. U. 7(2002-2003) no policy implementation has resulted to date. Sources of new supply, accounting for a significant portion of the increased rates sought in this Application, were also exempted by Government from the Board's jurisdiction. In considering these issues the Board is cognizant of its statutory obligations to consumers to ensure an equitable and adequate supply of power at the lowest possible cost consistent with reliable service. Following this, NLH's second Application as a fully regulated utility, the Board believes ambiguity exists involving Government and NLH such that public policy considerations should be appropriately reviewed in advance of NLH's next general rate application. These issues are addressed separately in this Decision and Order.

Pace of Regulation

Since NLH's 2001 general rate application was its first since becoming a fully regulated utility in 1996, in Order No. P. U. 7(2002-2003) the Board expressed concern with the pace of regulation. This Order directed NLH to file its next general rate application before December 31, 2003, and ordered NLH to fulfill a considerable number of regulatory requirements. NLH submitted its original Application on May 21, 2003 in advance of the deadline and met the numerous regulatory directives of the Board in a timely and thorough fashion. The Board commends NLH and its staff for their responsiveness to Order No. P. U. 7(2002-2003). The Board believes that the regulation of NLH is now proceeding at an acceptable pace and looks forward to sustaining this momentum following this Decision and Order.

Decision Criteria

In Order No. P. U. 7(2002-2003) the Board noted its regulatory decision-making would balance both short and long term goals and convey a clear and consistent message to stakeholders. The Board favours sustainable policy/decision-making which contributes to a supportive and stable regulatory environment. The Board will focus on proactive and sustainable policy/decision-making throughout this Decision and Order.

Focus for the Future

In implementing a sound regulatory environment for NLH the Board emphasized in Order No. P. U. 7(2002-2003) it would focus on implementing appropriate policies and procedures for the ongoing regulatory supervision of the utility. The Board respects NLH's right to manage the utility in the manner it sees fit. The Board has once again in this Decision and Order focused on broad based planning and policy considerations including strategic and corporate goals linked to corresponding management and operating performance measures, integrated resource planning, business improvement processes, productivity/efficiency initiatives and improved regulatory reporting and accountability.

The Board acknowledges NLH remains in transition in terms of its operation as a fully regulated utility. This situation is not unexpected in that effective regulation will require the ongoing commitment of the utility, the Board and other stakeholders. The strategic considerations outlined in Order No. P. U. 7(2002-2003) continue to reflect a sound foundation on which to regulate NLH in the future.

2. Current Industry Structure

The following provides an update to the current industry structure contained in Order No. P. U. 7(2002-2003).

Electrical services in the Province of Newfoundland and Labrador are provided by two utilities, NLH, which is a Crown corporation, and NP, an investor owned subsidiary of Fortis Inc. NLH is principally responsible for generation and transmission in the Province, with a relatively small amount of distribution in predominately isolated rural areas. NP operates solely on the Island portion of the Province and is primarily a distribution company with some generating capacity.

Together NLH and NP supply, transmit and distribute electricity to 255,100 domestic and general service customers. NP's operations on the Island service 220,000 customers or 86% of all general service and domestic customers. NLH serves the remaining 14% or 35,100 customers as well as 4 regulated industrial customers and 1 non-regulated industrial customer.

There are two major electrical systems operating within the Province. The Island Interconnected System functions as a stand-alone system comprising various hydro-electric developments and thermal power generated at Holyrood. The Labrador Interconnected System is supplied by Churchill Falls and is connected to the North American power grid. The more remote and isolated areas of the Province are serviced by individual diesel generating facilities owned and operated by NLH.

The table on the following page updates the generation capacity on the Island since NLH's 2001 general rate application.

Island Generation Capacity (MW)				
	2001[1]		2003[2]	
Producer	**Capacity**	**%**	**Capacity**	**%**
NLH Island Hydro	887.4	48.27	927.3	48.13
NLH Island Thermal	598.2	32.54	598.2	31.05
NLH Isolated Island	7.9	0.43	7.6	0.39
NP	147.4	8.00	147.4	7.65
Deer Lake Power	121.4	6.58	121.4	6.30
Abitibi Consolidated	58.5	3.15	58.5	3.04
Non Utility	19.0	1.03	66.3	3.44
Total	**1839.8**	**100%**	**1926.7**	**100%**

[1] Order No. P. U. 7 (2002-2003), pg. 17
[2] Extract : (Pre-filed Evidence, J. R. Haynes, Schedule II);
(Revised Evidence, F. H. Martin, Schedule IV, Aug. 12, 2003).

The net increase in Island generation capacity is primarily attributable to new sources of supply as follows:

Producer/Source	Change
NLH Island Hydro	
- Granite Canal	+40.0
Non-Utility Generators/Power Purchased Agreements	
- Corner Brook Pulp and Paper Limited	+15.0
- Exploits River Hydro Partnership	+32.3
Total Increase in capacity	**87.3**
Less: NLH Isolated Island	- 0.3
Net Increase in capacity	**87.0**

(Pre-filed Evidence, J. R. Haynes, pg. 34)

On the Island NLH has approximately 1,533 MW of installed capacity consisting of 927.4 MW of hydro-electric generation from Bay d'Espoir, Upper Salmon, Cat Arm, Hinds Lake and Granite Canal, 598.2 MW of thermal generation from Holyrood and various gas and diesel units and 7.6 MW of isolated diesel generation. NLH also owns 3,380 km of high voltage transmission lines, and 2,516 km of distribution lines.

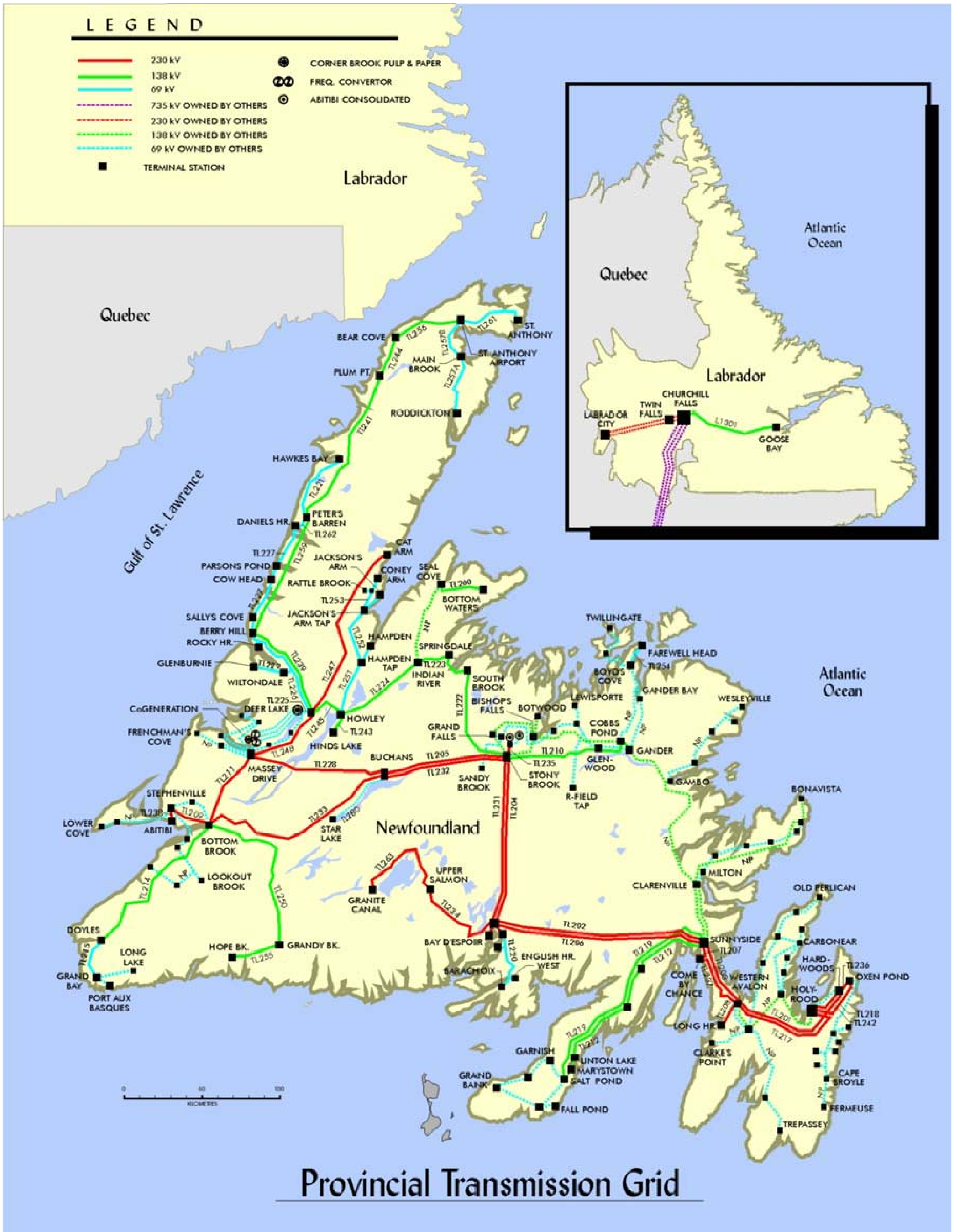
NP's generating capacity is 93.2 MW from its various hydro-electric generating sites and 54.2 MW from thermal generation. NP purchases approximately 90% (4,772.7 GWh forecast for 2004) of its energy requirements from NLH.

Energy generated by Deer Lake Power and Abitibi Consolidated Company of Canada is used primarily for paper mill operations in Corner Brook and Grand Falls-Windsor respectively. In situations where energy production exceeds operational requirements at the mills, NLH will purchase the excess for the Island grid, as required and if it is cost effective. Under agreements, NLH also purchases power from four Non Utility Generators: the Star Lake Hydro Partnership (15 MW); Algonquin Power (4 MW); Corner Brook Pulp and Paper Limited (15 MW); and the Exploits River Hydro Partnership (32.3 MW).

On the Island system NP operates in the majority of areas excluding the South Coast, Little Bay Islands and St. Brendan's. In these areas service is supplied by NLH using 8 isolated diesel generation and distribution systems. Service is supplied to the Great Northern Peninsula by NLH through the Island Interconnected System.

In Labrador NLH provides service to all customers. Power is purchased (2,362 GWh in 2003) from Churchill Falls to supply the Labrador Interconnected System consisting of the Towns of Labrador City and Wabush and the Happy Valley-Goose Bay area. In the isolated coastal areas NLH operates 16 diesel generation facilities with a combined capacity of 22.9 MW. NLH also buys a small amount of energy from a private company in Mary's Harbour and secondary energy, when available, for the L'Anse au Loup system from Hydro Quebec's Lac Robertson hydro plant. For the L'Anse au Loup system, forecast energy requirements in 2004 will largely be met by .466 GWh of diesel operation and 16.34 GWh of power purchased from Hydro Quebec.

The Provincial Transmission Grid and the Provincial Isolated Systems (Diesel) are shown on the following pages.



(Revised Evidence, F. H. Martin, Schedule II, Aug. 12, 2003)

(Revised Evidence, F. H. Martin, Schedule III, Aug. 12, 2003)

IV. STATUTORY POWERS AND RESPONSIBILITIES

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

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

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

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

1. Board Authority

Mandate

The Board's authority is derived from its statutory powers and responsibilities as set out in the *Public Utilities Act* (the *"Act"*) and the *Electrical Power Control Act 1994 (S.N. 1994, Chapter-E-5.1)* (the *"EPCA"*).

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

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

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

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

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

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

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

Section 4 of the *EPCA* states:

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

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

Form of Regulation

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

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

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

Statutory Limitations

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

> *"5.1 Notwithstanding section 3 and section 4 of the Act and the provisions of the Public Utilities Act, the Lieutenant-Governor in Council may direct the public utilities board with respect to the policies and procedures to be implemented by the board with respect to the determination of rate structures of public utilities under the Public Utilities Act and, without limiting the generality of the foregoing, including direction on the setting and subsidization of rural rates, the fixing of a debt-equity ratio for Hydro and the phase in, over a period of years from the date of coming into force of this section, of a rate of return determination for Hydro and the board shall implement those policies and procedures.*
>
> *5.2 The Lieutenant-Governor in Council may exempt a public utility from the application of all or a portion of this Act where the public utility is engaged in activities that in the opinion of the Lieutenant-Governor in Council as a matter of public convenience or general policy are in the best interest of the province, to the extent of its engagement in those activities."*

Appeal Process

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

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

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

Stated Case

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

1. The *Act* should be given a liberal interpretation respecting the purpose of the legislation and the power policy of the province;
2. The Board has discretion in how it approaches its mandate;

3. The Board has all appropriate and necessary powers;
4. The Board must balance the interests of public utilities and electrical consumers;
5. The Board sets rates prospectively, after a full consideration of all available evidence; and
6. The Board has discretion to choose the approach to setting rates as long as it observes the legislation and sound utility practices.

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

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

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

2. Board Procedures

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

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

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

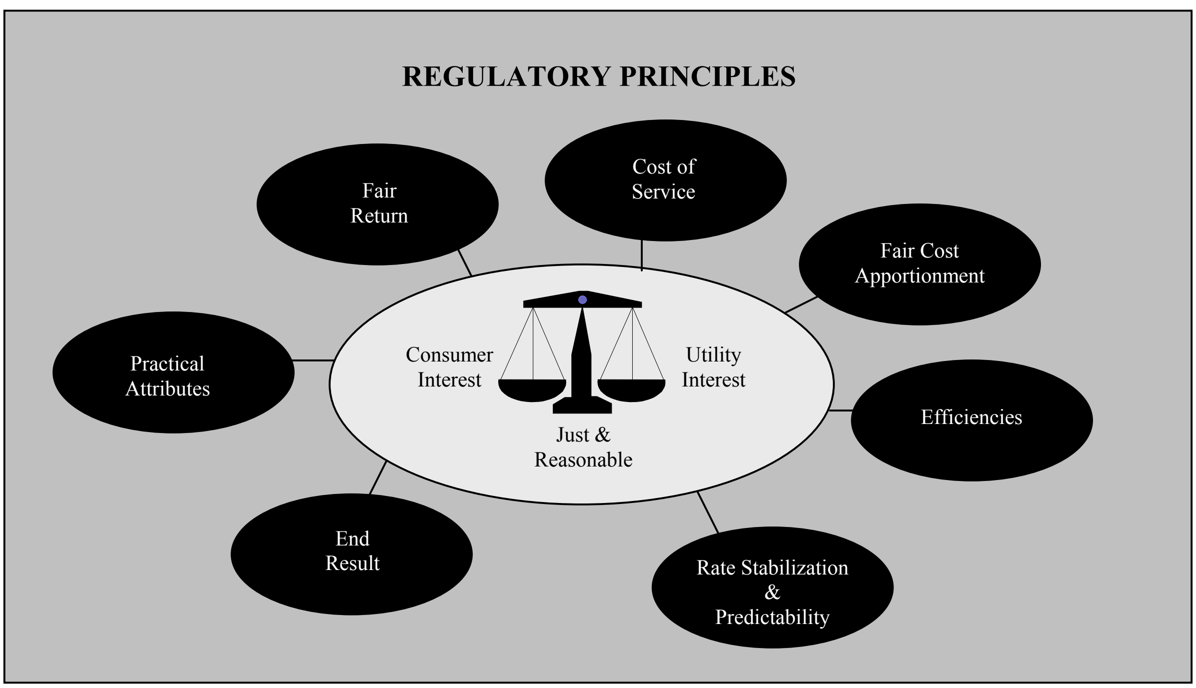
Through these procedures the Board ensures that the process is accessible and transparent for stakeholders, including the public. The Board may also travel throughout the province to hear from interested persons or organizations. Full and informed public debate and discussion on the issues is encouraged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

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

3. Regulatory Principles

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

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



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

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

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

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

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

3. <u>Fair Cost Apportionment</u>

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

4. Efficiencies

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

5. Rate Stability and Predictability

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

6. End Result

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

7. Practical Attributes

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

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

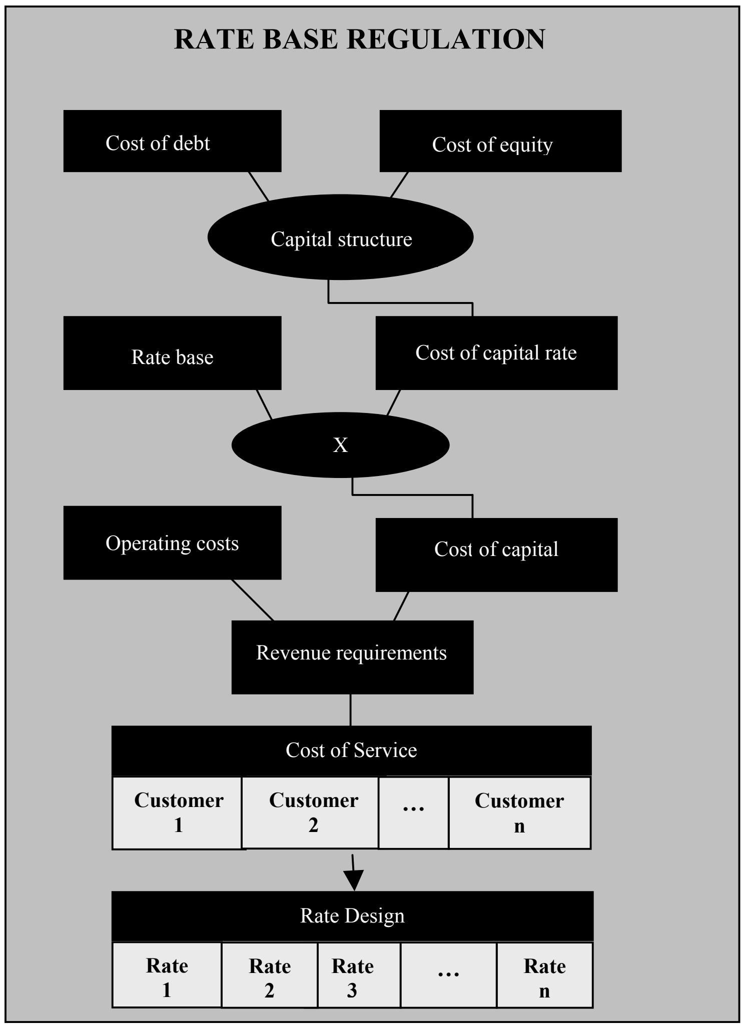
During rate proceedings the Board is often petitioned by intervenors and presenters to consider the customers' ability to pay when setting rates for various classes of customers and service. While cross subsidization of a group of customers contributing toward the cost of service assigned to another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

4. The Rate Setting Process

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

Rate Base Regulation

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



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

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

Rate Base

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

Capital Structure

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

Revenue Requirement

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

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

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

Cost of Service

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

Rate Design

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

5. Reporting/Compliance

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

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

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

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

6. Summary

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

PART TWO. BOARD DECISIONS

I. CAPITAL STRUCTURE AND RETURN ON EQUITY

In its initial Application NLH proposed financial targets which included a return on equity (ROE) of 10.75% and a capital structure of 80% debt and 20% equity. NLH submitted it had no less business risk than a typical investor owned utility and, therefore, was prepared to accept the same return on equity as NP, the other regulated utility in this jurisdiction. Following the subsequent issuance of Order No. P. U. 19(2003) involving NP's most recent general rate application, NLH revised its proposed ROE to 9.75%, equivalent to that ordered for NP.

As was the case with NLH's 2001 general rate application, the evidence concerning NLH's capital structure and ROE was inextricably linked to issues of ownership, provincially guaranteed debt and treatment of NLH as an investor owned utility.

1. Government Guarantee

The Provincial Government guarantees NLH's debt. The Province receives compensation in the form of an annual fee equivalent to 1% of the previous year's total debt (net of sinking funds) outstanding as of December 31st. The evidence is clear that the ability of NLH to maintain a sound credit rating in the financial markets of the world is dependent on this Government guarantee, as was found by the Board in Order No. P. U. 7(2002-2003). NLH acknowledged this in its final argument referring to Ms. McShane's pre-filed evidence. (Final Argument, NLH, pg. 24/12-14) Ms. McShane noted NLH would not be financially viable at either its forecast or target capital structure in the absence of the guarantee and further noted that the guarantee enables NLH to raise debt at yields equivalent to those of the Province. (Pre-filed Evidence, K. McShane, pg. 19/6-8) Dr. Kalymon concurred that the financial structure of NLH would not be financially viable without the Provincial guarantee. (Pre-filed Evidence, Dr. B. Kalymon, pg. 11/7-8) Dr. Waverman commented the debt guarantee allows NLH to carry a higher proportion of debt in its capital structure than could be justified by an investor owned utility. (Pre-filed Evidence, Dr. L. Waverman, pg. 11/22-25) NP observed the guarantee fee enables NLH to borrow at reasonable rates that could not otherwise be achieved with NLH's capital structure. (Brief of Argument, NP, pg. C-14/19-20) In final argument the IC commented that the legislation is clear that NLH must secure and maintain a sound credit rating and that all parties to the hearing agreed that this comes by way of the Government guarantee. (Written Argument, IC, pg. 7)

NLH indicated the guarantee fee to be $14,684,000 for the 2004 test year. (Revised Evidence, J.C. Roberts, Schedule VII, Oct. 31, 2003) The methodology used in this calculation was supported by Grant Thornton's 2003 General Rate Hearing Report (pg. 12/6-9) which explained that the guarantee fee increased more than $2,000,000 over 2002 due to additional bond issues in 2002 and 2003 (pg. 36/22-24). CA-3 (Table 14) shows the guarantee fee decreasing to an estimated $13,200,000 in 2007 due primarily to declining long-term debt.

In final argument, NLH contended no party at the hearing raised any issue with respect to the amount of the guarantee fee included in the 2004 interest expense category. (Final Argument, NLH, pg. 24/24-25) Ms. McShane submitted it is extremely unlikely under most (if not all) market conditions that NLH, with 80% debt and no debt guarantee, could raise long-term debt at a rate less than 100 basis points above that of the Province and therefore the guarantee fee of 1% is reasonable. (Pre-filed Evidence, K. McShane, pg. 20/4-7) Dr. Kalymon expressed the view that the guarantee fee of the Province is not excessive if recognition is given to the fact a portion of the fee is providing compensation for the implicit equity investment. (Pre-filed Evidence, Dr. B. Kalymon, pg. 16/11-13) NP took no issue with the payment of the guarantee fee or its benefit to customers. (Brief of Argument, NP, pg. C-14/18-19)

The Board accepts the level of the guarantee fee as being reasonable. The Board acknowledges the crucial role played by the Government guarantee in sustaining NLH's creditworthiness and enabling the utility to borrow in the capital markets at reasonable rates. Mr. Roberts stated NLH's position for the short term over the next five to seven years is for an 80/20 capital structure with continuation of a guarantee fee. (Transcript, Oct. 15, 2003, pgs. 127/4-13; 128/12-24) Mr. Roberts further acknowledged that a 60/40 capital structure reflecting a stand-alone credit rating without a guarantee is not practically achievable for NLH within a 10-15 year time horizon. It is recognized by the Board that the Government guarantee fee will be necessary to ensure NLH's creditworthiness into the foreseeable future.

The Board accepts that the Government guarantee plays a key role in supporting NLH's ability to maintain a sound credit rating in the financial markets of the world and to access needed capital at reasonable rates.

2. Dividends/Capital Structure

Beginning with the 1995/96 Provincial budget, NLH has been paying an annual dividend to Government as its sole shareholder. Whereas the initial dividend policy called for the dividend payment *not to cause a deterioration in the existing debt/equity ratio of the Corporation,* [Order No. P. U. 7(2002-2003), pg. 37], this policy was revised as follows:

> *"In May 2000 Hydro's Board approved a change in the dividend policy so that dividends of up to 75% of Hydro's net operating income before net recall revenue for the year plus 100% of net recall revenues received could be paid as a dividend provided that such payment shall only be made after due consideration has been given by the Board of the impact of such payment on the debt/equity ratio of Hydro. Net recall revenue commenced in 1998 when Hydro began selling power recalled under the CF(L)Co Power Contract to Hydro-Quebec.*"
> (Pre-filed Evidence, W. E. Wells, Schedule II - Discussion Paper on Hydro Dividends, pg. 2)

The historic and forecast dividends paid to Government in relation to both NLH's net regulated operating income and its resulting debt/equity ratio is shown on the following page.

Year	Dividends Paid During Year - ex Recall and CF(L)Co $(000)'s	Net Regulated Operating Income $(000)'s	As a % of Net Regulated Operating Income	Debt/Equity Ratio %
1995	14,500	22,829	64%	80.6/18.4
1996	9,688	20,693	47%	81.2/18.8
1997	12,357	31,351	39%	79.9/20.1
1998	10,489	24,847	42%	79.0/21.0
1999	1,309	13,015	10%	79.2/20.8
2000	10,026	5,829	172%	79.4/20.6
2001	9,773	11,918	82%	80.4/19.6
2002	65,723	9,743	675%	85.1/14.9
2003(F)	5,564	(4,110)	-	86.4/13.6
2004(F)	14,005	18,674	75%	86.0/14.0
Total	**153,434**	**154,789**		

F-forecast
Sources: (i) Pre-filed Evidence, W.E. Wells, Schedule II – Discussion Paper on Hydro Dividends, pgs. 2, 3 & 6;
(ii) Revised Evidence, J.C. Roberts, Schedules II, V, IX, Oct. 13, 2003;
(iii) Grant Thornton's 2003 General Rate Hearing Report, pg. 11;
(iv) CA-98; and
(v) CA-175.

While Order No. P. U. 7(2002-2003) acknowledged the payment of dividends as a matter between NLH and its shareholder, Government, the Board at the time expressed concerns regarding the extraordinary dividend (forecast $70,000,000) proposed for the test year 2002, both in terms of its impact on electrical consumers as well as NLH's target capital structure. The Board ordered interest expense and return on equity in the 2002 test year revenue requirement to be adjusted in keeping with NLH's stated dividend policy of 75% of net operating income and accepted NLH's proposals for a test year debt/equity ratio of 83/17 and a target short term debt/equity ratio of 80/20. The Board also recommended in Order No. P. U. 7(2002-2003) that NLH consult with Government on establishing a mutually appropriate and predictable dividend arrangement on a go forward basis. Acting on this recommendation, NLH held various meetings with senior levels of Government and prepared a Discussion Paper on this issue. The Discussion Paper was forwarded to the Deputy Minister of Mines and Energy on March 25, 2003. In the accompanying letter Mr. Wells stated the following:

"The Board expressed its concern that in the absence of a predictable and stable dividend policy, it would be difficult for either NLH or the Board to target an appropriate capital structure, or achieve it within a predictable timeframe."

"Hydro, in consultation with its financial consultant, will be proposing a Debt/Equity ratio of 80/20, as its financial target. The Hydro Board had earlier confirmed that 80/20 was an appropriate Debt/Equity ratio for Hydro in 1996. If dividend payments remain at 75% of net income, Hydro would not be able to reach that target. In fact, it will require dividend payment of not more than 50% of net income for Hydro to achieve an 80/20 Debt/Equity ratio by 2010."

Further, NLH concluded in its Discussion Paper (pg. 7):

"Hydro is suggesting that the current dividend payout policy of 75% would be replaced by a dividend policy of paying out 50% of net operating income. This policy would be fixed for the next five years and facilitates movement to the proposed debt to capital structure. It would also contribute to rate stability and predictability. Failure to adhere to such a policy could result in similar disallowances by the Board, thereby adversely impacting on shareholder returns".

NLH's response to PUB-87 indicates Government had advised NLH that it is considering the information on NLH's dividends and that Government will advise accordingly when decisions are made. NLH indicated a reply had not been received from Government to date. (Final Argument, NLH, pg. 45/9-11)

In final argument NLH reiterated the position outlined in its Discussion Paper to Government that its goal is to move towards the target capital structure of 80/20 over the next five years, which will require a modification of the current dividend policy. NLH suggested the evidence is clear that the forecast capital structure for 2004 of 86/14 does not adversely affect NLH's financial viability because of the provincial guarantee. NLH further submitted it is appropriate for the Board to endorse the target capital structure 80/20 recommended by Ms. McShane as a reasonable objective towards maintaining its self-supporting status. (Final Argument, NLH, pg. 45/1-19) NLH noted the 80/20 capital structure was accepted as a short term target in Order No. P. U. 7(2002-2003) and was recommended in a Board report as far back as 1992. (Final Argument, NLH, pg. 44/28-30)

NP argued NLH does not have the minimum equity in its capital structure which its own financial expert considers appropriate for a Crown owned utility and further, its capital structure has actually weakened since 2002, with a debt component that has increased from 83% to 86%. NP submitted NLH does not have a supportive dividend policy to permit material improvement in its capital structure and has not yet been able to formulate and implement a sound financial plan to achieve the capital structure appropriate for a Crown owned utility. NP accepted that the payment of dividends is a matter primarily between NLH, its Board of Directors, and its shareholder Government, but pointed out that NLH has an obligation under the *EPCA* to establish a capital structure that ensures long-term financial strength and creditworthiness and that consumers should not bear the consequences of NLH not having a sound financial plan in place to achieve this objective. (Brief of Argument, NP, pgs. C-13/16-26; C-14/1-7)

Both the Board and NLH have obligations in accordance with the power policy of the Province to maintain through their respective actions and decisions the long-term financial integrity and creditworthiness of NLH, which includes consideration of its capital structure as outlined in Section 3(a)(iii) of *EPCA*. Despite repeated goals set by NLH and endorsed in previous Board Orders of an 80/20 debt to equity ratio, the capital structure of NLH continues to deteriorate to where the forecast for 2003 and test year 2004 shows the greatest variance from this stated goal since the payment of dividends began in 1995. Since 1995 to test year 2004 forecast, the net operating income of NLH has been $154,789,000 with $153,434,000 or 99.1% paid out in dividends to Government.

According to its own expert, Ms. McShane, NLH's current and forecast capital structure exceeds the upper end of reasonableness (80% debt) which rating agencies view as compatible with a self-supporting Crown corporation, even backed with a government guarantee. (Pre-filed Evidence, K. McShane, pg. 17/4-5) Ms. McShane further explained that, while debt rating agencies are concerned with NLH's financial parameters on a consolidated basis and NLH's consolidated debt has been less than 70% since 1996, there is a low probability in the short term that a higher than target debt ratio (for the regulated entity) will impair the Province's debt rating. However, Ms. McShane maintained that a failure to progress toward the target will be perceived as an inability to operate as a self-supporting commercial enterprise. (Pre-filed Evidence, K. McShane, pgs. 17/24-26; 18/5-7) Dr. Waverman confirmed that those who rate NLH's debt pay close attention to the *"self-supporting"* rating of NLH, which mitigates concerns about the Provincial contingent liability given the debt guarantee. (Pre-filed Evidence, Dr. L. Waverman, pg. 6)

NLH was not in a position during this proceeding to express with any clarity Government's disposition regarding NLH's future retained earnings. While the Application is premised on NLH's current 75% dividend policy, it was clear from the evidence that the current 86/14 debt to equity ratio will only be reduced by 2008 to either 85%, 83%, or 81% depending on the respective dividend payout of 75%, 50% or 25% of annual net operating income and the allowed ROE. (Revised Evidence, J. C. Roberts, Aug. 12, 2003, pg. 10/Table 2) The Board received no assurances as to which of these scenarios holds the most likely prospect for NLH or, for that matter, whether or not a further extraordinary dividend may be required from retained earnings. Mr. Roberts did not rule out the potential for further deterioration of the capital structure should Government require additional funds from NLH as part of its equity. (Transcript, Oct. 15, 2003, pg. 134/17-20) Mr. Roberts noted the financial risk is represented by the degree of leverage associated with the capital structure and the more debt versus equity, the greater the leverage, and the greater the financial risk. Furthermore, if there is little equity, financial flexibility of NLH is reduced. (Pre-filed Evidence, J. C. Roberts, pg. 9/14-22) NLH maintains no financial plan to reach its target capital structure of 80/20 other than financial projections which are based on the existing 75% dividend policy and this assumption provides no significant improvement in the existing capital structure to 2008. NP and the IC noted that NLH has all but abandoned this prospect in this Application. Ms. McShane concurred it is not a practical goal given the only source of equity capital available to NLH is through retained earnings. (Transcript, Dec. 3, 2003, pg. 94/6-14; Written Argument, IC, pg. 7/10-11)

While continuing to acknowledge that the payment of dividends is a matter between NLH and its shareholder, Government, the Board has obligations concerning the impacts that such dividends/practices have on NLH as a regulated utility and hence its ratepayers. The Board is compelled by the evidence of Ms. McShane which states:

> *"The ability of Hydro to attain its target capital structure is dependent on maintaining a supportive dividend policy in conjunction with a fair and reasonable return on equity. A supportive dividend policy is one which is predictable to both shareholders and management and thus permits reasonable planning on the part of both. It is also compatible with both the level of the utility's capital budget and the objective of maintaining a reasonable and stable capital structure. The predictability of the dividend policy is also in the best interests of ratepayers, who*

are then provided with the assurance that the cost of capital they incur in rates will be equal to the cost incurred by Hydro."
(Pre-filed Evidence, K. McShane, pg. 17/4-14)

Ms. McShane further stated:

A. (Ms. McShane) Well, I think that we have to, sort of start, where we are. And I do believe that based on what the debt rating agencies see other crown corporations doing, that if it continues to see Hydro's debt ratio staying at the current level or deteriorating, that it will have a tendency to view this corporation as not being fully self supporting. And I think it's important for Hydro to take its proposed change in dividend payout to the shareholder and convince that it's important for them to build up the equity in the corporation.
(Transcript, Dec. 3, 2003, pg. 92/12-23)

The Board concludes the only certainty regarding NLH's forecast capital structure is that it is uncertain. Mr. Wells stated:

A. (Mr. Wells) So, I don't know what the government's position, indeed in the circumstances in the province today, I mean, things may change. We just don't have an answer; we're not sure.
(Transcript, Oct. 9, 2003, pg. 25/10-13)

The Board emphasizes one of the key principles of sound regulatory practice is to maintain a stable and predictable regulatory environment which will foster a degree of certainty for management and a fairness and stability in electrical rates for consumers. The Board concludes that the uncertainty surrounding the dividend policies/practices of NLH and its shareholder, Government, does not afford the protection needed to ensure lowest cost, stable and predictable rates. Mr. Wells commented:

A. (Mr. Wells) Without assurances with respect to NLH's financial integrity the overall cost to supply electricity to customers will be higher over the longer term.
(Transcript, Oct. 6, 2003, pg. 72/5-12)

While Mr. Wells is referring in this statement to the need for NLH to sustain an appropriate return commensurate with risks in order to maintain lowest cost power in the long term, the same can be said for NLH's capital structure.

With regard to establishing an appropriate dividend policy, the Board agrees that management makes recommendations to the Board of Directors of NLH who adopt a position on a particular issue, but ultimately it is the shareholder who would have the final say. (Transcript, Dec. 3, 2003, pgs. 103/13-18; 104/6-7) The IC argued Government has ultimate control of the debt/equity structure of NLH and has demonstrated its propensity to withdraw funds from NLH according to its own requirements, regardless of the financial position of NLH. (Written Argument, IC, pgs. 9-10) In Order No. P. U. 7(2002-2003) the Board recommended that a mutually appropriate and predictable dividend policy would have to be resolved between NLH and Government in advance of this Application. No such policy was established.

Ratepayers are deserving of rates founded on a reasonable and stable capital structure premised on a predictable dividend policy, either an explicit policy established between NLH and its shareholder, Government, or a policy deemed by the Board in setting rates. The latter remains the only alternative available to the Board in this Decision.

The Board was presented with no evidence opposing a targeted capital structure for NLH of 80/20. The Board endorses once again NLH's proposal, as recommended by Ms. McShane, for a target capital structure of 80/20 debt to equity in order to ensure NLH is able to maintain its self-supporting status. The ultimate achievement of this objective is in the best interests of NLH and its ratepayers in contributing to fair and stable electrical rates. It is clear from the evidence that an 80/20 capital structure will only be realized by NLH within a reasonable period with a supportive and commensurate dividend policy being adopted by NLH. Ms. McShane indicates a reduction in the payout ratio is a reasonable approach to manage the achievement of the proposed capital structure ratios. (Pre-filed Evidence, K. McShane, pg. 17/18-20) Since the Board has no jurisdiction concerning the dividend policy or the actual payment of dividends by NLH to Government, the Board can only determine what dividends will be allowed for the purpose of setting rates. The evidence reflects a dividend policy of 25% of annual net operating income is most compatible in moving toward a self-supporting capital structure (80/20) within a reasonable timeframe consistent with NLH's stated objective. The Board notes a dividend policy of 75% will marginally reduce the existing 86/14 capital structure to 85/15 by 2008 and a 50% dividend policy, as recommended by NLH in its Discussion Paper to Government, will only effect a reduction in capital structure to 83/17 by 2008. A dividend policy of 25% will reduce the existing capital structure to 81/19 by 2008. (Revised Evidence, J. C. Roberts, Aug. 12, 2003, pg. 10, Table 2)

The Board finds that a dividend policy of 25% of annual net income is most supportive of NLH's stated objective of moving toward a capital structure of 80/20 within a reasonable time frame. For purposes of determining the 2004 test year revenue requirement, NLH will be ordered to adjust the forecast dividend payment in 2004 to 25% of net income from the proposed 75% payout, incorporating the impact of this adjustment on the forecast ROE and interest expense.

3. NLH as an Investor Owned Utility

In its 2001 general rate hearing NLH submitted it operated as an investor owned utility and should be treated as such for purposes of regulation. Order No. P. U. 7(2002-2003) determined:

> *"The Board finds no statutory basis for treating NLH as an investor owned utility. The Board concludes approval in principle of NLH's request to be treated as an investor owned utility is not justified based on its current operating characteristics. The Board believes NLH's request is premature in the absence of a sound plan by NLH of how it will achieve financial targets similar to an investor owned utility and what impact this will have on its customers. The Board notes that NLH's debt is guaranteed by Government and this ensures NLH's continued access to the capital markets of the world."*

Although the question concerning NLH as an investor owned utility changed somewhat in this proceeding, evidence once again centered on this issue as one of the key considerations in determining an appropriate return on equity for NLH. NLH submitted that it is entitled to the opportunity to earn a just and reasonable return reflecting the level of business and financial risks NLH faces, which it argued, have been acknowledged to be no less than that of the other utility operating in the Province, NP, an investor owned utility. (Final Argument, NLH, pg. 48/25-28) NLH argued, however, that the distinction of whether a utility is Crown owned or investor owned is meaningless since ROE should be the same for either type of utility having similar capital structure and similar risks. (Transcript, Jan. 16, 2004, pg. 41/5-11) Both Mr. Wells and Mr. Roberts clarified that NLH's position with respect to being treated as an investor owned utility relates to the assessment of NLH's rate of return based on the risks of the equity holder. (Transcript, Oct. 9, 2003, pg. 22/1-13; Oct. 16, 2003, pg. 18/17-22)

All intervenors presented evidence on this issue and unanimously agreed no change in the Board's findings in Order No. P. U. 7(2002-2003) was warranted by the current circumstances surrounding NLH.

The CA submitted NLH has failed to demonstrate since Order No. P. U. 7(2002-2003) that there has been significant change in its key operating characteristics, and noted that in fact negative change has occurred regarding NLH's capital structure. The CA acknowledged that without the cooperation of its shareholder, the Provincial Government, NLH cannot be faulted for not meeting the standards required by the Board to qualify as an investor owned utility. The CA concluded NLH should not be treated by the Board as an investor owned utility. (Final Submission, CA, pg. 9; Transcript, Jan. 16, 2004, pgs. 54/20-25; 55/1-4)

NP noted NLH has the burden of proving that it is entitled to be treated as an investor owned utility and hence entitled to an investor owned utility ROE. NP submitted that NLH must demonstrate it has a sound plan to achieve the financial and operating characteristics appropriate for NLH as a Crown owned utility. NP suggested that to date NLH has made little or no progress in this area and has actually moved backwards on the key issue of capital structure. NP argued NLH has not proven it is entitled to be treated as an investor owned utility and has effectively abandoned that objective. NP concluded NLH should be regulated as a Crown owned utility, not an investor owned utility. (Brief of Argument, NP, pgs. C-8/4-25; C-17/8-18)

The IC argued NLH presented similar attributes in this Application to those denoted in 2001 in comparing itself to an investor owned utility. The IC concurred generally with the CA and NP that there is no evidence which has satisfied the conditions laid down by the Board for treatment of NLH as an investor owned utility. (Written Argument, IC, pg. 8)

Dr. Waverman indicated NLH is a Crown corporation and raises capital by issuing debt, supported by the unconditional guarantee of the Province as to principal, interest, and where applicable, sinking fund payments. Given these facts Dr. Waverman concluded that NLH's consideration of its optimal capital structure, Provincial dividend payment policy, and cost of equity will be different from those of an investor owned utility. (Pre-filed Evidence, Dr. L. Waverman, pg. 9/1-5)

The Board agrees with the conclusions of the intervenors that NLH has demonstrated little progress since the issuance of Order No. P. U. 7(2002-2003) to warrant treatment as an investor owned utility. In Order No. P. U. 7(2002-2003) the Board outlined a number of enabling requirements toward its treatment of NLH as an investor owned utility. These included: (i) targeted financial plans; (ii) a supportive dividend policy; and (iii) an appropriate capital structure. These requirements have not been met and in actual fact the latter two have deteriorated since NLH's last general rate application when compared to an investor owned utility. NLH's future dividend policy remains in doubt and hence NLH has submitted no financial plan to date toward achieving a self-supporting capital structure consistent with an investor owned utility. In addition, Mr. Wells acknowledged no plan has been developed by NLH to evaluate the impact on customers of moving to what he describes as *"akin"* to an investor owned utility. (Transcript, Oct. 7, 2003, pg. 156/1-12)

NLH's response to PUB-86 describes the similarities between NLH and an investor owned utility. These similarities referenced an efficient and least cost operation as well as appropriate financial returns and capital structure based on an appropriate dividend payout. As noted by the IC, these characteristics are the same as previously outlined by NLH in its 2001 application. Order No. P. U. 7(2002-2003) noted at the time that at least two of these similarities, i.e. an appropriate debt/equity ratio and dividend payout, were not in keeping with an investor owned utility. Indeed, as evidenced earlier, NLH's capital structure versus an investor owned utility has actually deteriorated as a result of NLH's dividend payment to Government.

The Board also notes that Dr. Waverman confirmed that NLH's dividend policy and debt to equity ratio reflect differences between NLH and an investor owned utility similar to those outlined in 2001. Dr. Waverman further confirmed the unconditional provincial guarantee as another distinct difference between NLH and an investor owned utility. Order No. P. U. 7(2002-2003) notes the provincial guarantee was also among the principal differences outlined by NLH in its 2001 general rate hearing in distinguishing its operations as a Crown corporation from those of an investor owned utility. The other notable differences include the ability of the shareholder, Government, to direct NLH in matters of public policy and the fact that NLH is not subject to corporate income taxes.

The Board concludes there continue to be more differences than similarities between NLH and an investor owned utility. These differences remain exemplified in NLH's operations in respect of the provincial guarantee, capital structure, dividend policy, public policy direction and tax-exempt status. The Board notes these differences between NLH and an investor owned utility will continue to apply with no evidence of change occurring in the foreseeable future.

The Board does not accept the argument presented in this Application that nonetheless NLH remains entitled to an ROE as if it were investor owned based on the risks of the equity holder, Government. If NLH expects to be treated as an investor owned utility in one aspect of its operation then it must reflect this expectation in other aspects of its operations, including capital structure backed up by an appropriate dividend policy. As outlined in Order No. P. U. 7(2002-2003), NLH has the responsibility to demonstrate how it plans to achieve operating characteristics equivalent to an investor owned utility and what impact this will have on its customers. The Board is not persuaded that circumstances have changed sufficiently in this Application to warrant any different treatment of NLH as an investor owned utility than that determined in Order No. P. U. 7(2002-2003).

The Board finds insufficient justification at this time to warrant treatment of NLH comparable to an investor owned utility for purposes of setting its financial targets. The onus is on NLH in future applications to clearly demonstrate through its operations and financial plans how it will achieve financial targets similar to an investor owned utility and what impacts this will have on its customers. The Board will continue to recognize NLH as a Crown owned utility afforded the benefit of a debt guarantee provided by its shareholder, Government, which sustains NLH's access to the capital markets.

4. Return on Equity

NLH's proposed revenue requirement for the 2004 test year comprises a return on equity (ROE) of 9.75%, amounting to $18,674,000. (Revised Evidence, J.C. Roberts, Schedule II, Oct. 31, 2003) Mr. Wells explained that, in order to expedite this issue, NLH is proposing the same ROE of 9.75% that was recently approved for NP. (Revised Evidence, W. E. Wells, Aug. 12, 2003, pg. 22/16-22; PUB-85, pg. 1/6-9)

NLH's regulated return on average common equity for the period 2000-2004 is as follows:

Regulated Return on Average Common Equity					
	2000	**2001**	**2002**	**2003(F)**	**2004(F)**
Regulated Return on Common Equity (%)	2.10	4.44	4.03	-3.77	9.56

F – forecast
Source: (Grant Thornton's 2003 General Rate Hearing Report, pg. 14/15-28)

It is noteworthy that NLH's actual ROE for 2002 was in fact higher at 4.03% than the 3% ROE which was accepted by the Board in Order No. P. U. 7(2002-2003). The 2003 forecast shows an ROE of -3.77% primarily attributable to Granite Canal and power purchase contracts coming onstream. NLH's requested 9.75% ROE for the 2004 test year has been reduced to 9.56% as shown above to enable comparison with prior years. This calculation is outlined in NP-5 and primarily reflects the fact that NLH does not earn an ROE from rural assets.

The evidence summarizing the position of the cost of capital experts concerning ROE is outlined on the following page.

COST OF CAPITAL - EXPERT EVIDENCE			
	Ms. McShane	**Dr. Kalymon**	**Dr. Waverman**
Business Risk	- NLH faces no less business risk than the typical investor owned electric utility in Canada, including NP. (Pre-filed Evidence, pg. 13/9-11)	- Business risk of NLH has not changed materially from the last hearing and is similar to other electrical utilities such as NP (Pre-filed Evidence, pg. 10/21-24)	- NLH faces many of the same business risks (i.e., weather, the economy, the price of inputs, etc.) that confront IOUs. (Pre-filed Evidence, pg. 9/23-24)
Financial Risk	- Debt guarantee transfers to the guarantor (in this case the Province) much of the financial risk associated with the debt to NLH, thus permitting it to operate with a higher debt ratio than a stand-alone utility. Assumes a stand-alone capital structure (i.e. no debt guarantee) of 60/40 in determining ROE. (Pre-filed Evidence, pgs. 14/1-9; 21/15)	- Capital structure risk of NLH continues to be very high but with Provincial guarantee the financial risk is limited to Provincial credit level. Deemed capital structure of 60/40 used to calculate ROE. (Pre-filed Evidence, pg. 13/6-13)	- NLH does not have common stock equity investors and does not face the risk with these investors borne by IOUs. (Pre-filed Evidence, pg. 9/24-29) - Other factors that tend to lower the costs and risks for NLH include the debt guarantee, tax-exempt status and Crown corporation (Pre filed Evidence, pgs. 11/16-25; 12/1-6)
Total Risk	- Total risk of NLH comparable to NP. (Transcript Dec. 3, 2003, pg. 124/1-6)	- Overall risk of NLH comparable to average utility and below NP. (Pre-filed Evidence, pg. 13/11-13)	- Debt investors in NLH bear less risk than common shareholders in IOUs meaning that WACC which utilizes an IOU proxy group's costs of common equity for NLH's retained earnings would result in rates for NLH's customers that contain capital charges in excess of NLH's costs. (Pre-filed Evidence, pg. 12/7-12)
Debt Guarantee Fee	- Total compensation to the debt guarantor should be no greater than if NLH was financed on a stand-alone basis. (Pre-filed Evidence, pg. 21/6-7)	- The guarantee fee of the Province is not excessive if recognition is given to the fact that a portion of the fee is providing compensation for the implicit equity investment. (Pre-filed Evidence, pg. 16/11-13)	- 1% guarantee fee can be recognized either as an interest expense (preferred by Dr. Waverman) or part of the opportunity cost of capital but not both. (Pre-filed Evidence, pg. 15/16-23; Transcript, Jan. 16, 2004, pgs. 179/1-25; 180/1-19)
Shareholder's Equity	- The equity funds reinvested in NLH by the Province have an opportunity cost. The Province (and taxpayers as shareholders) should expect to earn a return on the equity funds reinvested in NLH equivalent to the return they could have earned on an alternative investment of comparable risk. (Pre-filed Evidence, pg. 24/21-25)	- Given a deemed 40% equity, the Province is entitled to earn an ROE similar to that of other companies of similar risk. (Pre-filed Evidence, pg. 14/8-10)	- NLH, a Crown corporation, has no common stock equity and the Province's citizens are its ultimate "owners". Compensating these owners simply means raising through regulated rates funds sufficient to maintain operations and satisfy:(1) the interest obligations on the outstanding guaranteed debt; and (2) the opportunity cost of the Province's citizens (as represented by the marginal cost of the Provincial guaranteed debt) for the shareholder's equity portion of the capital structure. (Pre-filed Evidence, pg. 5/13-21)
ROE Methodology	- 3 standard regulatory tests: 1) Equity Risk Premium 2) Discounted Cash Flow 3) Comparable Earnings. (Pre-filed Evidence, pg. 25/1-7)	- 3 standard regulatory tests: 1) risk premium method; 2) adjusted comparable earnings 3) discounted cash flow (Pre-filed Evidence, pg. 18/7-12)	- Focus on cost standard where comparison of NLH and IOU capital costs are irrelevant. (Pre-filed Evidence, pgs.7/28-29; 8/1-2) - Uses existing capital structure reflecting actual balance of debt to retained earnings (Pre-filed Evidence, pg. 8/23-25) - ROE equals embedded cost of NLH's outstanding provincial guaranteed debt (if not allowed as interest expense) plus the opportunity cost of shareholder's equity (retained earnings) at the marginal cost of new provincially guaranteed debt. (Pre-filed Evidence, pg. 3/6-15)
Recommended ROE	- **11.0 to 11.25%** (Transcript, Dec. 3, 2003, pg. 45/2-3)	- **8.5 to 9.0%** (Transcript, Dec. 4, 2003, pgs. 8-9)	- Long-term opportunity cost of new debt to NLH. Dr. Kalymon indicated as **5.83%**; accepted by Dr. Waverman. (Transcript, Dec. 4, 2003, pgs. 3/18-19; 58/14-21)

NLH explained that its request for a 3% ROE in its 2001 general rate hearing was intended to apply only for a limited time to address what was thought to be a temporary issue of adjusting base rates to reflect higher fuel costs. NLH indicated it cannot compromise the utility's financial integrity by continuing at a rate of return that was recognized by all to be well below market and well below what NLH is entitled to earn under current legislative provisions. (Final Argument, NLH, pg. 47/13-20) NLH argued that following a review of the relevant risks, NLH faces no less business risk than the typical investor owned utility in Canada, and noted Dr. Kalymon reached a similar conclusion. NLH again reiterated Ms. McShane's evidence that, in light of the sensitivity of the ROE to the capital structure, the debt cost and the guarantee fee, the equity return for NLH should be set at a level no less than that applicable to an average risk Canadian utility. In order to expedite resolution of ROE in this application, NLH requested a return on common equity of 9.75%, the same as recently allowed by the Board in Order No. P. U. 19(2003) for NP, an investor owned utility.

While not taking issue with Government's policy to subsidize rural rates, the CA argued that Government, as shareholder of NLH, should not receive a 9.75% ($19,000,000) ROE at the same time as ratepayers are expected to pay for the $41,000,000 rural deficit. The CA submitted that Section 3(a)(iii) of the *EPCA* creates a redundancy in allowing a utility to charge electricity rates sufficient to enable it to earn a return for the purpose of maintaining a sound credit rating when, in actual fact, NLH's sound credit rating is established by other means, namely the Government guarantee and NLH's consolidated financial parameters. The CA also submitted that when assessing NLH's appropriate range of ROE the Board should consider the fact that NLH's shareholder, Government, is entitled to collect a 1% guarantee fee amounting in the 2004 test year to $14,500,000. The CA noted this combination of the revenue required for the guarantee fee of $14,500,000 plus the 9.75% ROE of $19,000,000 equals an estimated $34,000,000, or 16% of NLH's total equity of $206,000,000. While not the total return per se, the CA claimed it provides some perspective on the level of return being received by the shareholder. The CA concluded there is no justification in the evidence for the Board to increase NLH's 3% ROE allowed in Order No. P. U. 7(2002-2003). Alternatively, the CA indicated if the Board decides NLH should be treated as an investor owned utility, then Dr. Waverman's approach should be accepted or, if not, Dr. Kalymon's evidence is preferred over that of Ms. McShane. (Final Submission, CA, pgs. 9-16)

NP submitted NLH maintains a sound credit rating and has appropriate interest coverage for its capital borrowing requirements. NP observed the Board should consider the degree to which it is appropriate to reduce NLH's ROE below normal returns in order to incent NLH to develop and implement a sound financial plan in the long term interests of the consumers of the province. NP suggested NLH will have time to develop a sound financial plan before its next general rate application. NP argued the Board will have to exercise its judgement in setting an appropriate ROE, taking into consideration the financial return to Government from the guarantee fee and the social policy benefits directed by Government through NLH's operations. NP concluded this is not simply a matter that can be determined on a mathematical basis from the evidence. (Brief of Argument, NP, pgs. C-18 to C-19)

The IC argued it is inappropriate for the Board to grant NLH a rate of return comparable to an investor owned utility. The IC submitted the intent of the legislation is served by allowing sufficient interest coverage to ensure NLH's debt is self-supporting and that is the appropriate test to apply to a government owned utility which does not operate like an investor owned utility. The IC explained that NLH rationalized the 3% rate of return requested in 2001 in terms of limiting rate shock arising from increases in the range of 17% and suggested a similar finding is justified today when increases range from 22-29% for the IC. The IC observed the only real market the Board need consider relative to NLH's credit rating is the debt market since NLH issues no equity. Given that NLH's debt continues to be self-supporting and access to the capital markets is ensured through the provincial guarantee, the IC concluded it is difficult to justify anything more than the existing 3% ROE, particularly in light of the legislative directive to seek lowest cost electricity. The IC recommended the 3% ROE remain in place. Should the Board decide to evaluate a *"market risk"* for NLH as if it were a traded company, the IC maintained NLH's relative operating risks are minimal and manageable since NLH is a non-taxable entity and is afforded various protections through the RSP. The IC further indicated NLH's financial risk is essentially non-existent given the Government guarantee and the lack of competition. The IC concluded that appropriate adjustments to ROE should be made to reflect, among other things, NLH's lower risks and the non-taxability of the shareholder. (Written Argument, IC, pgs. 7-11)

In summarizing the evidence Board Hearing Counsel noted all three experts agreed that setting a fair return was a question of determining NLH's cost of capital. Board Hearing Counsel observed that while all three experts agreed that NLH should be compensated for its interest obligations on embedded debt and the opportunity cost of its retained earnings, there was a difference in opinion concerning how to measure the opportunity cost of those retained earnings. Board Hearing Counsel noted Ms. McShane and Dr. Kalymon both submitted the opportunity cost of the retained earnings should equal what a common stock investor would earn in a similar risk enterprise, while Dr. Waverman suggested it equals the cost to NLH of issuing new debt. Board Hearing Counsel commented that the methodology used to determine NLH's cost of capital must ultimately have a rational basis and, to this end, the Board must be satisfied that the approach as suggested by an expert is based on accepted and conceptually correct principles of financial theory and utility rate making. Board Hearing Counsel concluded that if the Board finds it is not appropriate to treat NLH as an investor owned utility, it may wish to consider employing Dr. Waverman's approach as a suitable interim measure for determining the cost of capital. Board Hearing Counsel further concluded this methodology can be revisited if and when NLH demonstrates to the satisfaction of the Board it can be treated as an investor owned utility. (Final Submission, Board Hearing Counsel, pgs. 5/4-5; 6/12-23; 7/1-6)

None of the options presented by the cost of capital experts were the recommended first choice of any of the parties. While NLH essentially adopted Ms. McShane's methodology into evidence, its proposal of 9.75% was considerably below the 11-11.25% recommended by Ms. McShane. For purposes of expediting the decision in this Application, NLH proposed an ROE equivalent to that recently approved for NP in Order No. P. U. 19(2003). Both the CA and the IC recommended no change in NLH's existing 3% ROE, with the CA arguing in favour of Dr. Waverman's approach as a preferred second choice over that of his own expert, Dr. Kalymon. NP indicated the Board should exercise its regulatory judgment in setting an appropriate ROE for NLH. Board Hearing Counsel suggested Dr. Waverman's evidence may be considered by the

Board as a possible interim determination pending NLH justifying an ROE equivalent to that of an investor owned utility.

As previously determined, NLH has not proven it should be treated as an investor owned utility and the Board finds it is not entitled to an ROE comparable to an investor owned utility. The Board does not concur it should assess ROE for NLH as an investor owned utility when it finds that other appropriate measures of an investor owned utility are not being observed by NLH. For a utility to be treated as an investor owned utility for the purposes of ROE, its operating and financial practices should be appropriately established, properly integrated and consistently applied similar to an investor owned utility. The Board does not accept as sound regulatory practice allowing a utility to invoke one investor owned measure (i.e. market driven ROE) and then allowing it to operate differently with respect to a related measure (i.e. capital structure). As noted previously, the Board believes moving to a self-supporting capital structure is in the best interest of NLH and its ratepayers in contributing to fair and stable electrical rates.

NLH further argued ROE should be determined in relation to utilities of similar capital structure and similar risks. The Board acknowledges all three cost of capital experts agreed that both NLH and NP are exposed to some of the same business risks. In addition, all three experts viewed the financial viability of NLH to be currently dependent on the Government guarantee. Assuming a 60/40 capital structure for NLH, Ms. McShane concluded the total risk of NLH was comparable to NP and Dr. Kalymon concluded that it was below that of NP. Dr. Waverman argued NLH does not have common equity stock, and other factors such as NLH's debt guarantee and tax-exempt status tended to lower financial risks for NLH compared to an investor owned utility. The IC cited some of these same reasons in arguing that NLH's operating and financial risk was nominal in comparison to an investor owned utility.

The Board agrees that NLH must operate in a financially self-supporting manner with regard to revenues and expenses so as to cover its interest costs and not impair the bond rating of the Province, thereby impairing its own bond rating. The Board also concurs with the view that NLH and NP have similar business risk but is not persuaded that NLH's total risk is comparable given NLH's reliance on the Government guarantee in sustaining its creditworthiness. The Board notes this dependence on the provincial guarantee has become even more acute since Order No. P. U. 7(2002-2003) in light of NLH's deteriorating capital structure. No specific adjustment to NP's 9.75% equivalent ROE was presented to the Board to account for diminished total risk.

Both the CA and NP referred to the need for the Board to take into account social policy benefits and the guarantee fee in considering the financial return to the shareholder, Government. Indeed the unconditional provincial guarantee and the ability of Government to direct NLH in matters of public policy were previously identified as two distinct differences between NLH and an investor owned utility. The CA observed that the $41,000,000 rural deficit, the $14,500,000 debt guarantee fee and the $19,000,000 (9.75% ROE) are all revenues that arguably link to NLH's shareholder, Government, that NLH is seeking to collect from ratepayers in this Application. NP argued the guarantee fee and social policy benefits are directed by Government through NLH's operations and the Board should exercise regulatory judgment on those items in setting an appropriate ROE for NLH.

NLH observed the issue of the impact of the rural deficit on ROE was not covered by witnesses in this hearing but was referenced in its 2001 general rate hearing by various witnesses who expressed the view at that time that the rural deficit and social policy should not influence the ROE although it may impact other things such as rate design issues. NLH maintained the issue of the guarantee fee has been covered before and found by the Board to be a fee for service and should not affect ROE. (Transcript, Jan. 16, 2004, pgs. 41/17-25; 42/1-4)

The Board has already determined the guarantee fee to be a legitimate expense of NLH as requested in its Application. The Board accepts Dr. Waverman's evidence that the guarantee fee can either be recognized as an interest expense or part of the opportunity cost of capital, but not both, since it would be double counting with ratepayers paying the shareholder twice for the same risk.

NLH argued there should be no difference between a Crown owned utility and an investor owned utility of similar risk in determining a fair ROE. At the same time, NLH maintained that two of the elements, i.e. debt guarantee and social policy considerations, which make NLH distinctive from an investor owned utility should not influence ROE. The Board notes that, while the shareholders of an investor owned utility may be entitled to an ROE based on a comparison to similar risk utilities, its revenues do not normally incorporate a guarantee fee and social policy benefits. The Board agrees with NLH that there was insufficient evidence to specifically show how the Board should consider an appropriate ROE for NLH in light of the social policy benefits derived by its shareholder, Government. The Board notes Government has directed the Board under Section 5.1 of the *EPCA* regarding the rural deficit. This issue is more specifically addressed in Part II - Section VIII of this Decision and Order.

In final argument (pg. 10) the IC referred to the tax rate of 30.58% that another investor would have to pay on dividends. Additional details on this issue were outlined in responses to IC-348 to IC-350. Given that Government, as sole shareholder of NLH, is a non-taxable entity, the IC reasoned the ROE can be reduced by an equal percentage. The Board is not persuaded to make such an adjustment based on this evidence.

In summary, the Board concludes NLH currently maintains financial characteristics inconsistent with those of an investor owned utility and, while its business risk is similar to that of NP, NLH's total risk is lower due to the role played by the provincial debt guarantee. The Board determines that NLH is not entitled to a 9.75% ROE equal to that approved in Order No. P. U. 19(2003) for NP, an investor owned utility. Furthermore, based on the evidence, the Board is not able to assess how, if at all, NLH's ROE should be impacted by social policy benefits directed by its shareholder, Government, and/or the non-taxable status of NLH and its shareholder. The Board is of the view that if intervenors wish these issues to be addressed in future then appropriate evidence be presented to allow the Board to reach a specific determination.

In denying NLH's request for a 9.75% ROE similar to NP, an investor owned utility, the Board accepts NLH's argument that the 3% ROE accepted by the Board in Order No. P. U. 7(2002-2003) for the 2002 test year was an interim proposal until NLH's next general rate application. The Board acknowledged at the time that consideration of a more normal return would be subject to a future request by NLH. The Board does not agree with the position of the CA and the IC that there is no justification for an increased ROE. The Board finds no reasoned foundation in utility ratemaking to support the 3% ROE and believes this level would not constitute a just and reasonable return for NLH. It may also prove a disincentive for NLH to move toward an 80/20 self-supporting capital structure.

The Board finds that the appropriate ROE for NLH is greater than 3% and lower than 9.75%. The Board concurs with NP that the determination of an appropriate ROE for NLH in the circumstances is not a matter to be determined on a mathematical basis from the evidence. Hence, the Board will exercise its regulatory judgment in setting an appropriate ROE.

The Board in the first instance refers to its regulatory framework as set out earlier in this Decision. In the Stated Case (para. 144), then Mr. Justice Green concluded that the Board has discretion to choose the best approach to setting rates as long as it observes the legislation and sound utility practice. Mr. Justice Green remarked:

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

In balancing the competing interests of the consumer and the utility the Board has determined that an appropriate ROE for NLH is greater than 3% and less than 9.75%. Within these parameters the Board was presented with no evidence to enable it to reach a specific determination, other than Dr. Waverman's approach equating NLH's ROE to its cost of issuing new debt.

Dr. Waverman concluded a fundamental tenet of utility ratemaking is that prices are based on costs (operating plus reasonable profit). Dr. Waverman submitted that NLH is a Crown corporation which raises debt capital supported by the unconditional guarantee of the Province. Given these facts Dr. Waverman noted NLH's consideration of its optimal capital structure, provincial dividend policy and *"cost of equity"* will be different from that of an investor owned utility. As a Crown corporation, Dr. Waverman observed NLH should strive to provide efficient, safe, adequate and reliable service to its customers, while earning returns that allow NLH to be self-supporting. For purposes of this rate proceeding Dr. Waverman stated the Board should: (1) use a capital structure that reflects NLH's balance of debt and retained earnings; (2) allow the utility to recover its embedded cost of debt; and (3) consider allowing an opportunity cost of capital on NLH's retained earnings that is equal to NLH's opportunity cost of debt. (Pre-filed Evidence, Dr. L. Waverman, pgs. 3/17; 8/23-27; 9/1-5; 18-21)

Dr. Waverman's approach is premised on the evidence that NLH has no common stock equity and the Province's citizens are its ultimate *"owners"*. For the shareholder's equity (retained earnings) Dr. Waverman submitted NLH need only compute the opportunity cost of its ultimate public *"owners"* - the people of the Province of Newfoundland and Labrador. (Pre-filed Evidence, Dr. L. Waverman, pg. 7/15/21) Ms. McShane and Dr. Kalymon on the other hand suggested the costs of NLH's retained earnings should be comparable to an investor owned utility of similar risk. This key point of departure between the cost of capital experts involves an important regulatory question for the Board. What should customers or ratepayers of a Crown owned utility pay for electricity to compensate the utility and its public *"owners"* for a return on their equity investment (ROE)? This question becomes further complicated by the fact that some of the same owners, i.e. taxpayers, are being advantaged by social policy benefits for which they would otherwise have to pay outside of electrical rates. The answer lies in sharing costs appropriately among ratepayers, taxpayers, and public "*owners*" and deciding whether or not a government-owned utility in circumstances similar to NLH is entitled to recover all costs from ratepayers, including an ROE comparable to that of an investor owned utility of similar risk. The Board has determined that NLH has lower risk than NP and is not considered equivalent to an investor owned utility for purposes of determining ROE in this Application. In regulating NLH at this stage, the Board will concentrate on providing compensation for NLH's debt guarantee, supporting a strengthening of NLH's financial position and providing a fair ROE for NLH. Under these circumstances, an ROE for NLH linked to the cost of public debt may be considered a fair and reasonable return to be paid by customers and ratepayers of a Crown owned utility to compensate its public *"owners"* for supplying electricity.

Regarding the allowed cost for the shareholder's equity portion of NLH's capital structure, Dr. Waverman noted that Ms. McShane stated that the long-term opportunity cost of new debt to NLH is about 6.75%. He also suggested that a review of the yields to maturity of other electric utility Crown corporation debt in Canada with bond ratings comparable to NLH would also be useful. Dr. Kalymon also discussed the cost of debt to NLH in his pre-filed evidence (pg. 61) and, during direct testimony on December 4, 2003, updated the trading yields of long-term bonds for the Province from 6.03% as of August 14 to a current number of about 5.83%. Dr. Kalymon stated *"Given the provincial guarantee, that basically implies that that's the effective borrowing cost for this company for long-term funds."* (Transcript, Dec. 4, 2003, pg. 3/18-22) Dr. Waverman confirmed 5.83% as his understanding of the current marginal opportunity cost of debt. (Transcript, Dec. 4, 2003, pg. 58/14-21) Based on the evidence the Board concludes that 5.83% is the long-term marginal cost of new debt to NLH and, hence, represents a fair and reasonable return for the shareholder's equity portion of NLH.

In examining this option from a regulatory perspective the Board notes that,

- By virtue of the Government guarantee, NLH will continue to maintain a sound credit rating and will have access to the capital markets for its borrowing, including new debt;
- An ROE of 5.83% supports regulatory principles of rate stability and predictability and moderates against rate shock; and
- An ROE of 5.83% may also provide an incentive for NLH, in concert with its shareholder, Government, to put in place the required measures to achieve NLH's targeted goals of an 80/20 capital structure and an appropriate ROE comparable to utilities of similar risk.

Based on the foregoing considerations, the Board accepts 5.83% as an appropriate end result in determining NLH's ROE in the current circumstances. The Board is of the view that Dr. Waverman's approach will allow NLH to fully recover its costs, including a fair ROE, in the context of the finding that NLH should not be treated as an investor owned utility. In this particular Application, NLH is limited to an ROE equal to the Province's marginal cost of debt calculated using its actual capital structure. The Board believes a 5.83% ROE equal to the Province's marginal cost of debt can be used as a suitable interim measure to determine NLH's cost of capital. The Board concludes this finding is in keeping with sound cost-based ratemaking principles and is consistent with findings of the Board in this Decision and Order. The Board concludes that its finding of a 5.83% ROE for NLH is fair, just and reasonable from the perspective of both the consumer and the utility in the current circumstances. The Board confirms that any change in this determination will depend on NLH justifying to the Board in a subsequent application that it should be treated comparably to an investor owned utility or providing other suitable rationale supporting an increased ROE.

The Board concludes that an appropriate ROE for NLH for the purposes of determining the weighted average cost of capital for the 2004 test year is 5.83%.

II. FORECASTING: PRODUCTION AND FUEL COSTS

1. Introduction

Section 3 (a)(ii) of the *EPCA* requires the Board to establish rates, wherever practicable, based on forecast costs for the supply of power for one or more years. In this Application NLH has based its revenue requirement on its forecast costs for the 2004 test year.

Accurate forecasting plays a key role in establishing test year costs. Forecasts of hydraulic and thermal production, the fuel conversion factor for No. 6 fuel at Holyrood, and the price of No. 6 and other fuels contribute significantly to the costs of power generation to be recovered in rates.

2. Production Forecasts

i) Test Year Hydraulic Production

The issue of the appropriate hydraulic data stream to be used by NLH in forecasting test year hydraulic production was considered at NLH's 2001 general rate application. In Order No. P. U. 7(2002-2003) the Board determined:

> *"NLH will be required to use the 30 year average annual hydraulic production of 4,425 GWh as the basis for the test year hydraulic forecast. The Board will also require NLH to commission an independent study into its current forecasting methodology to address the concerns raised in this hearing, including the issues of data reliability, long term trends and climate change. The terms of reference for this study should be filed with the Board in advance. The results of this study will be required to be filed with the Board as part of NLH's next rate application."*

In its Application NLH forecast the hydraulic production for the 2004 test year based on the 30-year average for water inflows for the existing plants and from a power and energy analysis for Granite Canal. The total forecast hydraulic production is 4,582.2 GWh, consisting of 4,358.2 GWh from existing plants and 224.0 GWh from Granite Canal. This compares to a 2002 test year hydraulic production of 4,425.0 GWh. (NP-64; Grant Thornton 2003 General Rate Hearing Report, pg. 25)

As directed by Order No. P. U. 7(2002-2003) NLH submitted with its Application a report Island Hydrology Review Final Report, completed by SGE Acres. (Exhibit JRH-2) Ms. S. Richter of SGE Acres also testified during the hearing with respect to the report. NLH has accepted the recommendations of this report, which are as follows:

1. The longest reliable reference inflow sequence (period of record) should be used for all NLH's operation, planning and rate setting purposes.
2. The inflow sequences presently used by NLH should be corrected to ensure internal consistency.
3. The same estimate of average annual energy from hydroelectric resources should be used for operations, planning and rate setting.

4. Computer simulation of the operation of the hydroelectric system using the reference inflow sequences should be used to estimate energy production and spill from NLH's hydraulic resources. NLH should review its in-house models and other models available and select one for these purposes.
5. NLH should continue to use its present inflow sequences and methodology for energy estimates until such time that the ratification of inflow sequences and selection of a computer model has occurred. The present records, even with minor inconsistencies, give better estimates of expected flows than shorter records.

NLH indicated that it will correct the internal inconsistencies with the Bay d'Espoir record and will also investigate possible simulation models so that, if approved by the Board, the results of the simulation will be available to be used by NLH as the hydraulic production forecast in subsequent rate applications. (Pre-filed Evidence, J. R. Haynes, pg. 29/20-24)

In final argument NLH submitted that, based on the evidence, the Board should direct NLH to file its next general rate application utilizing the full historic record available to determine the appropriate hydrological production record. NLH also stated that it is prepared to file with the Board the results of the SGE Acres review with respect to the internal inconsistencies and to update the Board on the final selection of the computer model. (Final Argument, NLH, pg. 17)

The Mediation Report (Appendix H) presented the following position on behalf of the parties:

> *"r. The appropriate hydraulic data stream for both hydraulic production projections and RSP calculations is long term. The Parties agree that Hydro has properly filed its case using the 30-year record at this time. The Board may consider using the full historic hydraulic data flow record in Hydro's next GRA after NLH addresses discrepancies identified in the Acres Island Study and Parties have had the opportunity to comment thereon."*

In final argument NP submitted that the 30-year record should continue to be used as the appropriate hydraulic data stream for both hydraulic production projections and RSP calculations. NP also submitted that the analysis in support of using a longer-term average for forecasting is not complete and that NLH should be requested to file the analysis for consideration upon completion. NP recommended that the Board not make any determination as to the appropriate period of record for use in determining the average annual energy for future applications until NLH has completed the required analysis and presented the results for review at a public hearing. (Brief of Argument, NP, pgs. B8; B9)

The IC argued that the appropriate process would be for NLH to file its full historic hydraulic data flow record with the Board and provide copies to the other parties at such time as the discrepancies identified in the Acres Island Study have been addressed and rectified. The parties should be provided with the opportunity to make submissions to the Board as to the acceptability of NLH's proposal at its next general rate application. (Written Argument, IC, pgs. 13-14)

The CA stated that, pursuant to the terms of the mediation agreement, the Board is free to direct NLH to use the full historic hydraulic data flow record in NLH's next general rate application. (Final Submission, CA, pg. 35)

In oral argument NLH submitted that, on the basis of the evidence before the Board, there is no reason for the Board to defer a final decision on this issue. (Transcript, Jan. 16, 2004, pgs. 15/20-25; 16/1-7)

The Board accepts the position of the parties as consented to in the Mediation Report with respect to the use of the 30-year rolling average to forecast hydraulic production for the 2004 test year. It is noted that this results in a decrease in fuel expense of approximately $6,000,000 from that which would have been forecast if the full historic record had been used with this Application. (Grant Thornton 2003 General Rate Hearing Report, pg. 52/35-37) Because of the RSP NLH is revenue neutral with respect to the actual time period used for the hydraulic production forecast. However, this lower fuel expense will translate into a lower revenue requirement to be recovered in base rates from NLH's customers as a result of this Application.

The Board has also considered the report of SGE Acres and the testimony of Ms. Richter. In Order No. P. U. 7(2002-2003) the Board expressed concern regarding the reliability of the data series that NLH was using for its forecasting, as well as long-term trends and the impact of climate change. This report has addressed these issues in a comprehensive manner and the Board accepts its recommendations. In particular, with respect to the characteristics of NLH's historic inflow sequences, Ms. Richter testified:

> A. (Ms. Richter) The Hydro records have some problems in regard to internal consistency arising principally from changes in methods of flow derivation and internal water balance accounting. These deficiencies can and should be corrected. Aside from these minor internal inconsistencies, the sequences appear to be free of systematic and random errors.
>
> (Transcript, Oct 28, 2003, pg. 6/4-11)

Ms. Richter stated that, because of the minor nature of these internal inconsistencies, it was recommended that all data continue to be used. (Transcript, Oct. 28, 2003, pg. 7/9-11) The study also confirmed that the data series does not exhibit any definitive recent trends or changes attributable to climate change. A survey of other utilities conducted by SGE Acres also found that most utilities use the longest available hydraulic record to develop estimates of expected production from hydraulic resources.

The Board is satisfied that the concerns raised during NLH's 2001 general rate hearing with respect to the methodology for estimating hydraulic production have been substantially addressed by the SGE Acres report. NLH has confirmed that the work is currently underway by SGE Acres to correct the internal inconsistencies in the data series and that it is in the process of selecting appropriate computer models for simulation as recommended by SGE Acres. NLH should file its next general rate application using the full historic hydraulic data flow record. The parties will then have the opportunity to examine and make submissions to the Board on NLH's efforts to address the outstanding issues identified in the SGE Acres report.

The Board accepts NLH's proposal to use the 30-year average for the estimation of hydraulic production for the 2004 test year, which will result in a total forecast hydraulic production of 4,582.15 GWh.

The Board will direct NLH to file its next general rate application using the full historic hydraulic data flow record with evidence demonstrating how the following outstanding issues have been addressed:

(i) correction of the internal inconsistencies in the data series; and
(ii) selection of an appropriate computer model for simulation.

ii) Test Year Thermal Production

NLH has forecast a total required energy supply for 2004 for the Island Interconnected System of 6,759.8 GWh. (Revised Evidence, J. R. Haynes, Schedule XI, Oct. 31, 2003) This energy supply will be provided from a combination of hydraulic generation and power purchases, with the difference provided by thermal generation at Holyrood, as shown below:

2004 Energy Supply Forecast	
Hydraulic Production	4,582.15 GWh
Energy Purchased	393.98 GWh
Thermal Generation	1,780.61 GWh
Total Energy Supply	**6,756.74 GWh**

(Revised Evidence, J. R. Haynes, Schedule VII, Oct. 31, 2003)

The Board has accepted NLH's proposal for the hydraulic production forecast of 4,582 GWh. No issues were raised by any of the parties with respect to NLH's test year forecasts for energy supply. Based on the evidence the Board will accept NLH's forecast for thermal production for the test year of 1,780.61 GWh, which will be used in conjunction with the fuel conversion factor and the forecast fuel price to determine the No. 6 fuel expense for the 2004 test year revenue requirement.

The Board accepts the 2004 test year forecast of thermal production of 1,780.61 GWh.

3. Holyrood No. 6 Fuel Conversion

The fuel conversion factor, or efficiency factor, is the expected kWh output from burning a barrel of No. 6 fuel at Holyrood (kWh/bbl) which, when applied to the forecast thermal generation, gives the expected barrels of No. 6 fuel required at Holyrood for the test year. The fuel conversion factor directly impacts NLH's test year fuel expense, as well as NLH's earnings and charges to the RSP.

In its 2001 general rate hearing NLH proposed an increase in the fuel conversion factor for No. 6 fuel at Holyrood from 605 kWh/bbl to 610 kWh/bbl. In Order No. P. U. 7(2002-2003) the Board ordered NLH to use a factor of 615 kWh/bbl in setting rates based in its 2002 revenue requirement. In this Application NLH is proposing to increase the conversion factor to 624 kWh/bbl. This increase in conversion factor results in forecast fuel savings in the 2004 test year of $1,200,000. (Pre-filed Evidence, J. R. Haynes, pg. 13/14-16)

According to NLH's response to NP-74 the proposed conversion factor of 624 kWh/bbl is the weighted average conversion factor for the period 1996 to 2002. This period was chosen because in 1995 NLH put in place a controllable losses program at Holyrood designed to assist the operator to optimize unit performance. The following table shows the achieved No. 6 fuel conversion factors for Holyrood since 1996:

Holyrood No. 6 Fuel Conversion Factor 1996 to 2002			
Year	**Net Energy Produced (GWh)**	**No. 6 Fuel Consumed (Barrels)**	**Conversion Factor (kWh/bbl)**
1996	1,403,596	2,297,258	611.0
1997	1,531,301	2,432,538	629.5
1998	1,263,264	2,041,605	618.8
1999	919,802	1,593,932	577.1
2000	970,283	1,591,586	609.6
2001	2,098,490	3,315,853	632.9
2002	2,385,262	3,678,183	648.5
Total	**10,571,998**	**16,950,955**	**623.7**

(NP-74)

In NP-310 NLH updated the No. 6 fuel conversion factor by month to the end of November 2003. The actual year to date conversion factor to the end of November 2003 is 636.3 kWh/bbl. In final argument NLH updated this information, stating that the actual conversion factor for 2003 to the end of December was 634.9 kWh/bbl. The actual average conversion factor for 1996 to 2003 was 625.4 kWh/bbl. (Final Argument, NLH, pg. 18/8-11)

NLH has undertaken a number of operating changes to improve productivity and efficiency with regards to the operation of the Holyrood plant. Because higher unit loadings result in higher efficiencies, initiatives that result in higher unit loadings are targeted while addressing other constraints such as the hydraulic situation, system security and voltage. According to NLH the controllable losses program introduced in 1995 to provide operations personnel with immediate data on plant processes has improved this effort. (Pre-filed Evidence, J. R. Haynes, pg. 12)

In response to IC-252 NLH indicated three specific projects in the last five years that will contribute to higher efficiency of the Holyrood plant. These include: i) Unit No. 3 water lance installation; ii) Unit No. 3 reheater retubing; and iii) continuous emissions monitoring system. The two projects related to Unit No. 3 were completed in 2001 and equate to a plant efficiency improvement of approximately 2 kWh/bbl. The continuous emissions monitoring project came on-line in the fall of 2003 and NLH predicts an increase of 3 kWh/bbl in plant efficiency. NLH stated that the impact of these projects on plant efficiency was considered in proposing the increase from 615 kWh/bbl to 624 kWh/bbl. (NP-267)

NP argued that NLH's proposed conversion factor is conservative and that a higher factor is more appropriate. Based on the expected plant operating conditions for 2004 and the initiatives to improve plant efficiency, NP submitted that a fuel conversion factor of 636 kWh/bbl is more appropriate. According to NP this value is based on the average of the conversion factors achieved for 1997 and 2001 which best approximates the forecast operating conditions for 2004. The average net energy produced in 1997 and 2001 was 1,814.9 GWh with a fuel conversion factor of 631 kWh/bbl. Given the similar operating conditions NP stated that a fuel conversion factor of 631 kWh/bbl would be more appropriate. NP recommended adding 5 kWh/bbl because of the efficiency improvements recently undertaken by NLH, for a proposed conversion factor of 636 kWh/bbl. (Brief of Argument, NP, pgs. B-11 to B-14)

The IC also submitted that the conversion factor proposed by NLH is too low. In final argument the IC stated that the conversion factor of 624 kWh/bbl is a simple mathematical average of actual production and barrels of fuel used since 1996. These numbers already take into account the variety of operating conditions which NLH faces but do not specifically take into account the efficiency improvements undertaken by NLH, and hence, according to the IC, an upward adjustment is required. The IC recommended a conversion factor of 636 kWh/bbl. (Written Argument, IC, pgs. 12-13; 44)

The Board agrees that the fuel conversion factor for forecasting 2004 test year fuel costs should be based on expected operating conditions for 2004. The actual average conversion factor for 1996 to 2003, which was updated by NLH's Counsel during final argument, is 625.4 kWh/bbl, which reflects a range of operating and hydraulic conditions. For the 2004 test year NLH is forecasting a thermal production of 1,780.61 GWh, 17.9% higher than the average production over the 1996-2002 period. Given that higher thermal production results in higher efficiencies (and hence a higher conversion factor), the Board agrees that 625 kWh/bbl appears conservative. As well the continuous emissions monitoring program completed in 2003 is expected to increase the efficiency by 3 kWh/bbl. The Board also notes that the actual conversion factors for the last three years have exceeded 632 kWh/bbl (2001 – 632.9 kWh/bbl; 2002 – 648.5 kWh/bbl; 2003 – 634.9 kWh/bbl). In the Board's opinion, given this recent experience and the fact that NLH has implemented programs to increase the efficiency at Holyrood, the evidence supports a conversion factor of 630 kWh/bbl.

The Board finds that a conversion factor for No. 6 fuel at Holyrood of 630 kWh/bbl is appropriate for the 2004 test year. This conversion factor will also be used in the RSP.

4. Fuel Price Forecasting

NLH uses PIRA Energy Group of New York, an international consultant, to forecast fuel prices for the purposes of determining NLH's fuel expense. PIRA provides a monthly World Oil Market Outlook, which includes any revisions to the short-term forecast and as well provides a quarterly longer-term market price forecast. (Pre-filed Evidence, J. R. Haynes, pg. 23/8-13)

NLH applies to this forecast received from PIRA foreign exchange rates which are calculated based on forecasts of major Canadian banking institutions. At the time of the May 21, 2003 filing the forecast average price for No. 6 fuel for 2004 was $29.20 (Cdn) per barrel based on an exchange rate of $0.66 US/$Cdn. (CA-112) This forecast was updated with the October 31, 2003 revised filing to a weighted average purchase price of $28.95 (Cdn) per barrel. (Revised Evidence, J. R. Haynes, Schedule VII, Oct. 31, 2003) The decrease was attributed to a slight decrease in forecast load, offset somewhat by an increase in the average cost of fuel from $29.42 per barrel to $29.50 per barrel. (Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, Note 17) The exchange rate forecast was also updated to $0.746 US/$Cdn. (NP-290) This more favourable exchange rate reduced the impact of the increase in fuel prices between the August and October filing.

In Order No. P. U. 7(2002-2003) the Board stated that it is required to set rates based on forecast costs for the test period and that the most prudent course of action was to set fuel prices at or near the price forecast for the test year. No intervenor at the hearing raised the issue of whether a price other than the forecast price for No. 6 fuel as filed by NLH should be used in determining test year fuel costs to be recovered in rates.

As with No. 6 fuel oil, the cost of diesel fuel is determined by applying forecast fuel prices as provided by PIRA to the fuel quantity required. The original forecast weighted average diesel fuel price, including seller's mark-up and delivery costs, was $0.433 per litre which was revised in NLH's October 31 filing to $0.403 per litre. (Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, Note 18)

The intervenors did not challenge NLH's forecasts for fuel costs or exchange rates and the Board accepts the forecast price for No. 6 and diesel fuel as reasonable.

The Board accepts the 2004 test year forecasts for fuel prices as proposed by NLH in its October 31, 2003 revised filing for determining the 2004 test year fuel costs.

III. REVENUE REQUIREMENT

1. Introduction

NLH requested a revenue requirement of $367,510,000 for the 2004 test year as set out in the Table below. The Board heard evidence on all of the elements contained in NLH's forecast 2004 revenue requirement.

NLH Revenue Requirement			
Description	**2002 Final Test Year Revenue Requirement[1] $(000)'s**	**2002 Actuals[2] $(000)'s**	**2004 Proposed Test Year Revenue Requirement[2] $(000)'s**
Depreciation	31,390	31,302	33,672
Fuel			
No. 6 Fuel	81,237	112,534	84,186
Diesel Fuel	6,508	6,766	6,801
Other Fuels	871	755	757
Rate Stabilization Plan	0	(46,807)	0
Total Fuel	88,616	73,248	91,744
Power Purchased	15,100	15,881	33,594
Other Costs			
Salaries and Fringe Benefits	61,926	64,559	63,242
System Equipment Maintenance	16,763	17,719	17,440
Insurance	977	1,198	2,019
Transportation	1,923	1,979	2,044
Office Supplies Expenses	1,864	1,856	1,913
Building Rentals & Maintenance	626	900	894
Professional Services	4,943	5,318	4,253
Travel	2,375	2,315	2,395
Equipment Rentals	1,558	1,372	1,756
Miscellaneous Expenses	4,398	4,674	4,185
Productivity Allowance	(2,000)	-	-
Loss on Disposal of Capital Assets	890	2,769	1,266
Subtotal	96,243	104,119	101,407
Allocations			
Hydro Capitalized Expense	(5,722)	(8,116)	(5,204)
CF(L)Co.	(1,910)	(2,006)	(1,858)
Non-regulated customer	(2,914)	(2,914)	(2,684)
Total Other Costs	85,697	91,083	91,661
Interest	88,298	88,547	98,165
Return on Equity	7,959	9,742	18,674
Revenue requirement	**317,060**	**309,803**	**367,510**

[1] Pre-filed Evidence, J. C. Roberts, Schedule II, May 21, 2003

[2] Revised Evidence J. C. Roberts, Schedule II, Oct. 31, 2003

2. Depreciation

NLH's depreciation expense in the 2004 test year is forecast to be $33,672,000, an increase of $605,000 over 2003, primarily due to additions to plant in service and the 2004 capital budget as approved by the Board in Order No. P. U. 29(2003). (Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003) Grant Thornton reviewed NLH's forecast depreciation expense for 2003 and 2004 and reported the depreciation expense appeared reasonable and was calculated in accordance with NLH's depreciation policies as approved by the Board in Order No. P. U. 7(2002-2003).

NLH's forecast depreciation expense for 2004 has increased by 4.9% since 1998. However, as a percentage of total assets it has declined from 1.96% in 1998 to 1.74% in 2004. As indicated by Grant Thornton in its report (pg. 34) this is a reflection of the annual capital expenditures incurred in each year.

In its review Grant Thornton noted that actual capital expenditures have been historically lower than budget and suggested that the Board might want to consider a downward adjustment of the depreciation expense to reflect this historic overbudgeting. The percentage variances of actual capital expenditures to budget for 1998 to 2002 are shown below:

Capital Expenditure Variance – 1998 to 2002	
Year	**% Under Budget**
1998	8.73
1999	16.70
2000	11.80
2001	13.15
2002	9.95
Average for the period	**14.44%**

(Grant Thornton 2003 General Rate Hearing Report, pg. 17)

Grant Thornton indicated that, based on its review, NLH is probably underspending by approximately 5%, and that the remaining 9% variance must be due to delays and carryovers.

Both NP and the IC argued that the forecast depreciation expense for the test year should be adjusted downward by the average of 14% for the period. (Brief of Argument, NP, pg. B-2/26-27; Written Argument, IC, pg. 16)

In final argument (pg. 39) NLH pointed out that its performance has been improving with an average underspending of 11.6% for the period from 2000 to 2002. NLH acknowledged that an adjustment for capital budget underspending is appropriate. NLH submitted however that the adjustment should be no more than 4%, which was the adjustment imposed by the Board on NP in 1996 and 1998 for underspending in similar circumstances.

For the purpose of establishing NLH's 2002 revenue requirement Order No. P. U. 7(2002-2003) ordered a reduction of 7.5% in the approved capital budget because of NLH's historic underspending. The Board recognizes that NLH has made progress in reducing variances between budgeted and actual capital expenditures. However, to recognize the fact that there has historically been underspending, the Board finds an adjustment to the 2004 capital budget is warranted for the purposes of determining the 2004 test year revenue requirement. The Board is not persuaded that a reduction of 14% is justified since, as noted by Grant Thornton, a portion of the underspending variance is due to carryovers and delays, which may not be within NLH's control. The Board will order a reduction in the approved 2004 capital budget for rate setting purposes of 5.0%, which is the amount of underspending identified by Grant Thornton. This adjustment also recognizes NLH's improvement in this area since its 2001 general rate application. This downward adjustment will reduce depreciation and interest expense as well as the forecast rate base for the 2004 test year.

Grant Thornton also noted that NLH's forecast capital retirements as a percentage of total assets appeared to be underbudgeted for 2003 and 2004 in comparison to the historic trend. Based on NLH's May filing, this trending is as follows:

Capital Retirements – 1998 to 2004								
	1998	**1999**	**2000**	**2001**	**2002**	**5-Yr Average**	**Forecast 2003**	**Forecast 2004**
Capital Retirements	5,740	6,676	6,330	6,911	7,743	6,680	2,891	2,654
% of Total Assets	0.35%	0.41%	0.38%	0.40%	0.44%	0.39%	0.15%	0.14%

(Grant Thornton 2003 General Rate Hearing Report, pg. 18)

The effect of increasing the 2004 retirements to the level of the five year average of 0.39% would result in a reduction in depreciation expense of approximately $168,000. Grant Thornton contends such an increase in retirements may also impact the forecast loss on disposal of assets. In addition, an increase in capital retirements would impact the forecast rate base for 2004 and consequently the return on rate base included in the revenue requirement. As with capital budget underspending, Grant Thornton suggested that the Board should consider an adjustment to the forecast capital retirements for the 2004 test year based on the historic levels. (Grant Thornton 2003 General Rate Hearing Report, pg. 19)

Mr. Roberts testified that NLH forecasts its known capital retirements associated with budgeted capital projects and that it is difficult to anticipate in any given year the magnitude of other assets that could be taken out of service prior to the end of their expected service life. According to Mr. Roberts the losses on disposal of retired assets would also have to be included in the revenue requirement and would exceed any reduction in depreciation expense and return on rate base that would arise should the amount of capital retirements be increased. (Transcript, Oct. 14, 2003, pgs. 12-13) NLH argued that, for the reasons set out by Mr. Roberts, it is not necessary to adjust the forecast capital retirements used in the determination of the 2004 test year revenue requirement. (Final Argument, NLH, pg. 41/1-3)

NP submitted that the evidence on this issue was unclear. (Brief of Argument, NP, pg. B-3/9) The other intervenors did not raise an issue with this particular expense.

The Board finds that an adjustment to NLH's 2004 revenue requirement to reflect the historic level of its capital retirements is warranted. For this purpose a factor of 0.39%, which is the five year average determined by Grant Thornton, will be used to determine the capital retirements as a percentage of total capital assets. The Board recognizes that there may be a consequential adjustment to the forecast loss on disposal relating to retired assets as well.

The Board accepts NLH's 2004 test year depreciation expense for the purposes of determining the 2004 test year revenue requirement subject to any adjustments arising from this Decision and Order, including:

- **i. a reduction of 5.0% in the approved 2004 capital budget; and**
- **ii. an adjustment to the forecast 2004 capital retirements to 0.39% of its total capital assets.**

3. Fuel Costs

i) Issues Arising from Order No. P. U. 7(2002-2003)

Order No. P. U. 7(2002-2003) directed NLH to file by December 31, 2002 a statement of policies and procedures outlining a coordinated, integrated and strategic approach to fuel purchasing, addressing managerial accountability along with consideration of an oil hedging program and the adequacy of existing storage facilities. The report Fuel Oil Practices Review And Policy was filed with the Board on December 23, 2002 and was also filed with this Application as Exhibit JRH-1. The following summarizes NLH's conclusions for each of these areas.

Oil Hedging Program

NLH retained the services of Risk Advisory, an independent risk management group, to review several aspects of an oil hedging program, including its goals, the type of programs in use, the benefits derived and the implications for the RSP. Risk Advisory recommended that, before proceeding with an oil hedging program, NLH should:

- (i) undertake a review of the added stability such a program would have in addition to the RSP; and
- (ii) if significant advantage was determined, consider a collaborative approach between the regulator and major intervenors to determine if there was consensus on the risk appetite of the ratepayer. (Exhibit JRH-1, pg. 2)

NLH's Oil Hedge Committee, after reviewing the Risk Advisory report, concluded that the potential significant cost in terms of administration, consulting services and regulatory burden associated with the implementation of a program would not be justified by the potential savings from a relatively small decrease in rate volatility. The RSP alone has the single greatest impact in terms of rate stability and predictability.

The findings of the report with respect to an oil hedging program were not challenged by the intervenors.

The Board agrees with the conclusion of Risk Advisory that, all things considered, the RSP alone has the greatest impact on fuel price variances. The Board also agrees with the conclusions reached by NLH's Oil Hedge Committee that there are no significant benefits at this time from further exploration of an oil hedging program.

Fuel Purchasing

NLH normally tenders on a three to five year basis for the supply of heavy fuel for the Holyrood Generating Station. NLH may also buy up to 25% of total supplies on the spot market; however, this option has seldom been used due to the volatility of oil prices on a daily basis.

In 2002 NLH retained United Fuels International to review its fuel specification both technically and contractually. This resulted in changes to the chemical content of the oil, changes in the price setting mechanism and a provision to move to a lower sulphur fuel.

The No. 2 diesel fuel used by NLH in its rural interconnected and isolated systems is tendered for the various locations and may be awarded to several vendors to minimize costs recognizing geographical and shipping economies.

NLH concluded that its fuel purchasing practices are adequate and in the best interest of ratepayers. This conclusion was not challenged by the intervenors. The Board agrees that NLH's current fuel purchasing practices are adequate.

Adequacy of Existing Fuel Storage Capacity at Holyrood

In light of the recommendation of NLH's Oil Hedge Committee that an oil hedging program not be implemented, NLH intends to continue its current method of purchasing fuel. In pre-filed evidence (pg. 22) Mr. Haynes stated that a minimum inventory of oil is always maintained which takes into account the range of demands on the plant during the year and potential shipping delays. Shipments are in the range of 250,000 to 300,000 barrels and require a 28-day notice under the contract. NLH maintains that the storage capacity at Holyrood has proven adequate to date and will continue to be sufficient to meet operational requirements into the foreseeable future. This conclusion was not challenged by the intervenors. The Board accepts NLH's conclusions regarding the adequacy of fuel storage at Holyrood and that further review will only be required when additional generation is considered necessary.

The Board accepts NLH's current fuel purchasing policies and practices.

ii) No. 6 Fuel

The cost of No. 6 fuel to be used at the Holyrood Generating Station represents the second major category of expense in the 2004 test year revenue requirement. NLH has proposed a test year revenue requirement for No. 6 fuel of $84,186,000. The forecast cost for No. 6 fuel depends on the forecast 2004 fuel price, the forecast fuel consumption and the forecast fuel conversion factor.

The Board has accepted NLH's thermal production forecast for 2004 of 1,780.61 GWh and NLH's forecast average weighted purchase price of $28.95 (Cdn) per barrel for No. 6 fuel. The Board set the conversion factor for No. 6 fuel at Holyrood at 630 kWh/bbl which will result in lower forecast fuel consumption for the 2004 test year and hence reduced No. 6 fuel costs.

The Board will direct NLH to reflect a fuel conversion factor of 630 kWh/bbl for No. 6 fuel at Holyrood in its 2004 test year fuel costs.

iii) Diesel Fuel

The second largest component of NLH's fuel expense category is diesel fuel. The 2004 test year cost is forecast to be $6,801,000. (Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003)

No issues with respect to the diesel fuel costs were raised by the intervenors and the Board accepts the test year cost as reasonable.

The Board accepts NLH's 2004 test year diesel fuel cost of $6,801,000.

iv) Other Fuels

An amount of $757,000 is included in the total fuel cost forecast for other fuels, which includes additives and indirects, ignition fuel, gas turbine fuel and environmental fees. (Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003)

No issues with respect to these fuel costs were raised. These costs compare to $871,000 included in the 2002 revenue requirement. The Board accepts these costs as reasonable.

The Board accepts NLH's 2004 test year costs for other fuels of $757,000.

4. Purchased Power

Purchased power expense is forecast to be $33,594,000 in 2004, an increase of $18,500,000 over the 2002 test year costs of $15,100,000.

On the Island Interconnected System NLH purchases power from two Non-Utility Generators (NUGS) at Star Lake and Rattle Brook, for a total forecast 2004 expense of $11,135,000. As well in 2003 NLH entered into two new agreements to purchase power with Abitibi Consolidated Company of Canada, as the agent for the Exploits River Hydro Partnership, and with Corner Brook Pulp and Paper Limited, which will provide a total additional capacity of 47.3 MW and average annual energy of 237 GWh. (Pre-filed Evidence, J. R. Haynes, Schedule II) The forecast purchased power expense for 2004 associated with these new purchased power contracts is $18,375,000, which accounts for almost all the increase in this expense category from the 2002 test year. The remaining $4,084,000 purchased power expense relates to the cost of purchases from Churchill Falls (Labrador) Corporation for customers on the Labrador

Interconnected System ($2,908,879), costs associated with the purchase of secondary energy for the L'Anse au Loup system from the Hydro-Quebec Lac Robertson Plant ($736,139), and other additional purchased power costs.

NLH's power purchase contracts with Corner Brook Pulp and Paper Limited and Abitibi Consolidated Company of Canada, as agents for the Exploits River Hydro Partnership, were exempted by Order-in-Council from the *Act* and the *EPCA*. The Board has also been directed by Order-in-Council to include the costs associated with these power purchases in NLH's expenses.

NLH's October 31, 2003 revised filing reflected an increase in costs for purchased power for Labrador Interconnected customers of $368,714. NLH described the primary reason for the increased costs as relating to an increase in previously unbudgeted costs of $331,784 for synchronous condenser maintenance and control upgrades at the Wabush Terminal Station. (NP-291)

In final argument (pg. B-44) NP submitted that, in the interest of rate stability, these costs should be deferred and amortized over a five year period beginning in 2004. In cross-examination by NP Mr. Roberts stated that *"these costs aren't necessarily extending a life of a particular asset, it's only ensuring that the actual estimated service life that's presently there is being and will be achieved."* (Transcript, Nov. 12, 2003, pg. 130/12-15)

NLH submitted that the Board should allow all of the costs forecast for purchased power for the 2004 test year.

With the exception of NP's submission regarding the Wabush Terminal Station expense, intervenors did not object to NLH's 2004 forecast purchased power expense.

The Board notes that the Wabush Terminal Station assets are owned by Twin Falls Power Corporation. NLH pays for the right of capacity in that Terminal Station and, by agreement, pays a proportionate share of the cost associated with any repairs that are done on that facility. (Transcript, Nov. 12, 2003, pg. 82/1-9) Given that NLH does not own the asset the Board is satisfied that these costs should not be deferred as proposed by NP but are appropriately treated as a recurring operating expense.

In light of the Government direction the Board accepts the costs associated with the two new power purchase agreements to be included in the 2004 test year costs. The Board also accepts the other elements of the power purchase expense estimated by NLH and included in the 2004 test year revenue requirement.

The Board accepts NLH's 2004 test year purchased power expense of $33,594,000.

5. Other Operating Expenses

i) Salaries and Fringe Benefits

The forecast expense of $63,242,000 for salaries and fringe benefits accounts for 63% of the *"Other Costs"* in NLH's 2004 test year revenue requirement, as follows:

2004 Test Year Salaries and Fringe Benefits ($000's)	
Salaries	$ 49,925
Director's fees	62
Overtime	2,869
Employee future benefits	3,727
Fringe benefits	7,110
Group Insurance	1,950
Labrador travel benefit	99
Vacancy allowance	(2,500)
Total	**$ 63,242**

(NP-304, pg. 2)

Mr. Wells testified that since 1992 NLH has eliminated 211 positions, representing a 21% reduction in NLH's permanent workforce and that approximately 10%, or nearly half of the total reduction, was achieved in the period 2000 to 2002. This reduction in workforce results from organizational changes, process improvements and technological changes. (Revised Evidence, W. E. Wells, Aug. 12, 2003, pgs. 8; 15/3-4)

The comparison of gross salary costs between the 2004 test year and the 2002 test year indicates an overall increase as follows:

Comparison of Gross Salary Costs - 2002 and 2004 (000's)	
Decrease in salaries (net of vacancy adjustment)	($ 1,166)
Increase in employee future benefits	1,294
Increase in fringe benefits	684
Increase in group insurance	270
Increase in overtime costs	248
Net Increase	**$ 1,330**

(Grant Thornton 2003 General Rate Hearing Report, pg. 41)

According to NLH its core wage expense has tracked below the rate of inflation since 1992. (Revised Evidence, W. E. Wells, Aug. 12, 2003, pg. 8, Chart 1) During cross-examination the IC requested a reproduction of this chart using 1997 as year one at the 100 index. (U-Hydro # 2) It showed that since 1997 NLH's core wage expense has tracked above the inflation rate, which, according to the IC, demonstrated that the comparison depends on what year is used as the base year.

NLH indicated that the elimination of 46 positions during 2002 will result in annual savings of $2,600,000. (Transcript, Oct. 15, 2003, pg. 153/14-18) These savings will be offset by forecast increases in union and non-union wages, using an effective date of January 1, 2004. (NP-14)

NP submitted that since NLH used a January 1, 2004 effective date to estimate the effect of wage increases, the 2004 test year salary costs should be reduced by $300,000 to more appropriately reflect the April 1, 2004 effective date for bargaining unit wage increases. (Brief of Argument, NP, pg. B-24/12-14)

NLH submitted that the 2004 forecast includes an increase in union wages as of April 1, 2004, as well as a 3% adjustment for non-union employees that became effective January 1, 2004. NLH argued that NP simply took the total increase and reduced it by a quarter, forgetting or ignoring the fact that over half of the salary/wage budget is for non-union employees who did get an increase as of January 1, 2004. In addition, there were progression increases for non-union employees as of January 1, 2004. NLH argued there is absolutely no evidence to support the reduction of $300,000 in salary expense. (Transcript, Jan. 16, 2004, pgs. 28/10-15; 29/1-12)

NP also argued that the 2004 test year salaries forecast should reflect $600,000 in savings due to the elimination of 10 FTEs in 2003 and $100,000 in savings related to changes in the area of meter reading. NP pointed out that the evidence of Mr. Roberts and Mr. Brushett indicates that this $700,000 in savings is included in the $2,500,000 vacancy allowance. (Brief of Argument, NP, pgs. B-24/17-19; B-26/14-17) NP believes that this is an inappropriate treatment of these savings and recommended that the Board order NLH to reduce its test year salaries by $700,000 to reflect the fact that these positions have already been eliminated from NLH's workforce in 2003. (Brief of Argument, NP, pg. B-27/1-2)

NLH argued that the salary savings of $700,000 were taken into account in the final salary numbers submitted to the Board and are reflected in the $2,500,000 allowance. NLH also argued that it would not have increased the allowance to $2,500,000 if the elimination of these positions had not been taken into account. (Transcript, Jan. 16, 2004, pgs. 29/20-25, 30/1-5)

NLH's test year vacancy allowance of $2,500,000 consists of $1,000,000 for normal vacancies (2.5% of $40,000,000 in permanent salaries) and $1,500,000 for future staffing reductions resulting from process improvement initiatives. (Transcript, Oct. 15, 2003, pg. 55/7-12) NP submitted, in its final argument (pg. B-29), that the $1,000,000 used to estimate normal vacancies is inadequate and does not reflect recent experience. Instead, using the average vacancy rate of 3.5% that has resulted from actual experience over the period from 1993 to 2001, NP argued this figure should be increased to $1,600,000.

Based on the evidence the Board is satisfied that the test year costs for salaries and fringe benefits includes the $700,000 associated with the elimination of 10 FTEs and meter reading. This amount is included in the vacancy allowance, as confirmed by NLH and Grant Thornton and acknowledged by NP in its final argument. (pg. B-26) While NP has requested the Board reduce NLH's salary costs by this amount, any such adjustment would require an adjustment in the vacancy allowance by the same amount. The result would be a decrease in both the salary forecast and the vacancy allowance, with no change in the test year salary costs. The Board will not order NLH to reduce its 2004 test year salaries by $700,000 as requested by NP, and accepts the test year salary costs as reasonable.

With respect to the vacancy allowance the Board is not satisfied that NLH's forecast of $1,000,000 for normal vacancies is adequate based on recent experience. NLH's response to NP-34 indicates the normal vacancy rate has averaged approximately 3.5%, compared to the 2.5% used by NLH in its Application. This would result in a normal vacancy allowance of $1,400,000. The Board also agrees with NP's argument that the normal vacancy allowance indicated for both 2003 and 2004 is approximately $1,600,000, based on NLH's average vacancies. The Board finds that a normal vacancy allowance of $1,500,000 should be used in the 2004 test year to reflect recent experience.

NLH has also added $1,500,000 to its normal vacancy allowance to provide for future staffing reductions resulting from process improvement initiatives currently underway. As discussed above this amount also includes the $700,000 in savings already realized as a result of NLH's business improvement processes. The Board is satisfied that this amount represents a reasonable target for savings in this area.

The Board also recognizes the confusion brought on by the transition to the FTE method of forecasting salary expense and is encouraged by the statement of NLH's Counsel, Ms. Greene, that *"In the future, you will only see the FTE basis, so I think that will simplify the process"*. (Transcript, Oct. 24, 2003, pg. 64/17-19) The Board expects NLH's next general rate application will include historical and forecast information stated in terms of FTEs.

The Board will direct NLH to reduce its 2004 test year salary expense by $500,000 to reflect a higher vacancy allowance.

ii) System Equipment Maintenance

System equipment maintenance is the second largest category of *"Other Costs"* expenses and accounts for $17,440,000 or 17% of the total *"Other Costs"* in the 2004 test year. The Holyrood Generating Station maintenance expense is $7,200,000 (Information #6) with the remaining amount used for projects such as maintenance of the transmission and distribution lines, hydraulic generating stations, isolated diesel and gas turbine generators and related equipment.

In Order No. P. U. 7(2002-2003) the Board directed NLH to submit by December 31, 2002 a detailed plan of projected maintenance expenditures for the Holyrood Generating Station for the next 10 years. The plan (Information #6) was filed on December 23, 2002 and addresses the operating maintenance expenditures for the years 2003-2013 inclusive. It was noted that generating Units Nos. 1 and 2, as well as the gas turbine, two of the main fuel storage tanks and other associated ancillary equipment are in excess of 30 years old. Unit No. 3 and the remaining two main fuel storage tanks are in excess of 20 years old. While many components of this equipment have been replaced and additional items added through the capital program over the years, numerous pieces of the original equipment and components still remain in service.

The Board acknowledges the significant expenditures associated with maintenance at the Holyrood thermal plant. The 10 year plan assists in monitoring the development of the overall maintenance program, both capital and operating, and is therefore a useful regulatory filing.

NLH pointed out that its 10 year plan of system equipment maintenance has to be viewed in the context of the harsh operating environment in which it operates and the age of the units, and changes to the plan that will result from unforeseen events. NLH contends that it is not possible to *"levelize"* the cost of maintaining a plant such as Holyrood where there are so many different operating systems and components. However, in order to meet customers' load and reliability expectations while controlling costs, NLH has pursued a proactive maintenance approach using sound engineering judgment to ensure its equipment is available for service as required. (Pre-filed Evidence, J. R. Haynes, pgs. 10-11)

In recent years NLH has adopted a Reliability Centered Maintenance (RCM) program which places emphasis on reliability and results in some systems receiving more frequent maintenance. NLH believes that this approach will result in a more effective and efficient maintenance program. The 2004 test year savings as a result of RCM are forecast to be $1,000,000. (CA-113; NP-277, pg. 1)

Order No. P. U. 7(2002-2003) directed NLH to present a summary report with recommendations on how it might improve reliability for customers in coastal Labrador communities. This direction was prompted by concerns raised by several coastal Labrador residents during NLH's 2001 general rate hearing concerning brown-outs, loss of supply, outages and customer service. The report Summary Report on Reliability and Quality of Service to Coastal Labrador Communities was filed with the Board on September 27, 2002. (CA-14) In this report NLH described a number of initiatives undertaken to address specific issues in these communities.

In addition to the specific actions taken to address the 2001 complaints in Nain, Charlottetown, Mary's Harbour and L'Anse au Loup, NLH has a number of ongoing initiatives to improve overall system performance, including reliability. These include electronic mechanisms on all new diesel engines to enable remote monitoring of performance, new or updated programs of engine replacement, condition based monitoring, RCM, tool inventory and Diesel System Representatives to provide multi-skilled personnel in isolated diesel areas. These initiatives have all been designed to give greater flexibility and improved customer service. The Board notes that complaints with respect to the service quality issues in coastal Labrador communities were not raised during the latest public presentations in Happy Valley-Goose Bay.

The intervenors did not raise any issues in relation to NLH's 2004 test year expense for system equipment maintenance.

The Board will require NLH's 10 year plan of maintenance expenditures for the Holyrood Generating Station to be updated annually to reflect changing operating circumstances.

The Board accepts NLH's 2004 test year system equipment maintenance expense of $17,440,000.

iii) Transportation

This category of expense is forecast to be $2,044,386 in the 2004 test year, as summarized below:

Transportation Expenses	
Aircraft fuel	$ 100,000
Aircraft costs	950,000
Vehicle fuel	1,058,996
Mobile equipment fuel	46,000
Vehicle rental	136,692
Vehicle allowance	52,698
Capital fleet	(300,000)
Total	**$2,044,386**

(Revised Evidence, J. C. Roberts, Schedule II; Oct. 31, 2003, NP-261)

Mr. Martin stated that NLH is in the process of conducting a review of both its on-road and off-road fleet of vehicles. (Transcript, Oct. 24, 2003, pgs. 100/15-25; 101/7-9) Mr. Martin explained that transportation expense gets credited with the costs incurred when vehicles are used on capital projects. This credit, which is forecast to be $300,000 in the 2004 test year, varies annually depending on the nature and amount of the capital projects. (Transcript, Oct. 24, 2003, pg. 113/18-22; NP-261)

NP raised an issue concerning the 2004 forecast transportation expense in relation to the reduced number of employees from 1998 to 2002. During that period the number of permanent staff declined from 889 to 801 while the number of vehicles rose from 274 to 282. (NP-10; NP-24) Mr. Martin explained that the reduction in staff would not necessarily relate to a reduction in vehicles since some layoffs have been in the engineering department and some have been clerical staff, neither classification being users of NLH vehicles. The increase in vehicles from 1998 to 2002 reflects the difference between 15 units purchased for capital projects and seven units eliminated due to fleet rationalization. (Transcript, Oct. 27, 2003, pgs. 8/2-21; 9/8-16)

NP submitted that NLH's vehicle operating costs have increased 25.6% from 2002 to forecast 2004 and that vehicles that were purchased for capital projects such as Granite Canal are now being charged to operations and maintenance, resulting in a reduction in capitalized vehicle costs. NP argued the Board should disallow the $185,000 increase in NLH's 2004 forecast vehicle operating expense because of a decrease in the utilization of vehicles on capital projects. NP noted that NLH is presently conducting a review of its vehicle fleet but have made no adjustments in the test year costs to reflect any savings. (Brief of Argument, NP, pgs. B-37/7-11; B-38/11-13)

Mr. Martin explained that aircraft transportation costs are primarily for leasing of helicopters. NLH pays a fixed retainer fee of $800/day for 365 days a year which, according to Mr. Martin, ensures the availability of transportation for repair crews during emergency situations.

Since NLH forecast a $150,000 reduction in its 2003 transportation (aircraft) expense NP argued a similar reduction in the 2004 transportation expense is warranted. (Brief of Argument, NP, pgs. B-38/24-25; B-39/10-11)

NLH submitted that 2003 was an anomaly which NLH does not expect to be repeated in 2004. (Transcript, Jan. 16, 2004, pg. 34/18-22)

The Board agrees that NLH has not shown sufficient justification for the $185,000 increase in vehicle operating expense due to the decrease in utilization of vehicles on capital projects. The Board is of the opinion that the completion of the Granite Canal project, resulting in a reduction in capitalized vehicle costs and a reduction in staff, should translate into a reduction in NLH's fleet of vehicles. As well the vehicle study, ongoing at the time of the hearing, may result in additional savings. The expense of $185,000, therefore, will be disallowed in the 2004 test year forecast. The Board will not order a reduction for aircraft expenses, as argued by NP.

The Board will direct NLH to reduce its 2004 test year transportation expense by $185,000.

iv) Miscellaneous Expenses

The table below shows the 2004 test year miscellaneous expenses:

Miscellaneous Expenses	
Staff Training	$712,649
Contributions (charities, etc.)	194,000*
Sundry Costs	81,818
Diesel Fuel Hydro	39,400
Demand side management	100,000
Employee expenses	322,526
Collection fees	8,520
Bad debt expense	324,996
Inventory gain/loss	370,000
Municipal and payroll taxes	2,224,694
	4,378,603
***Less: Non-regulated-Contributions**	(194,000)
Total	**$4,184,603**

(Information #9; Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, pg. 4)

Grant Thornton did not identify any particular concerns respecting the items included in this category of expenses and the forecast for the 2004 test year.

NP took issue with the amount of inventory gain/loss forecast by NLH for the 2004 test year. (Brief of Argument, NP, pg. B-42) NP noted that NLH undertook an initiative in 2001 to identify excess and obsolete inventory, resulting in a $1,000,000 write-off. The actual inventory write-off in 2002 was $306,000 lower than forecast. NP pointed out that the write-offs in 2003 and 2004 test year are significantly higher than experienced in 2002. NP submitted that NLH has not provided sufficient justification to increase forecast inventory write-offs in the 2004 test year and that the Board should order NLH to reduce this cost in 2004 by $132,000.

NLH argued that NP's submission:

> (Ms. Greene) ...neglected to point out that 2002 was not a representative year for write-offs. The response to NP-254 points out that the bulk of the inventory reductions forecast over 2001 and '02 were achieved in 2001, leading to an abnormally low 2002. So we believe that what's in the 2004 revenue requirement for inventory write-offs is consistent with past practice and that 2002, for the reasons explained, was an anomaly.
>
> (Transcript, Jan. 16, 2004, pg. 36/8-17)

The Board does not agree with NP that some of the elements, as described above, in the miscellaneous expense category should be reduced for the 2004 test year. The Board accepts the forecast costs for the miscellaneous expense category as reasonable.

The Board accepts NLH's 2004 test year miscellaneous expense of $4,185,000.

v) Other Cost Categories

In addition to the various expense categories dealt with in other parts of this Decision and Order, the remaining categories of operating expenses are forecast for the 2004 test year as follows:

Operating Expenses	
Professional Services	$ 4,253,000
Travel	2,395,000
Office Supplies	1,913,000
Insurance	2,019,000
Equipment rentals	1,756,000
Building rentals and maintenance	894,000
Total	**$13,230,000**

(Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003)

Professional Services expense relates primarily to consulting services, regulatory activities and the business improvement process which commenced in 2001. While this expense has exhibited a significant upward trend over the past four years, the forecast for 2004 test year reflects a decrease of 20.8% compared to 2002 actuals. The following is a summary of the professional services expense for the forecast 2004 test year compared with the actuals for 2002:

Professional Services Expense (000's)		
	2002 Actual	2004 Test Year
Professional Services	$ 3,315	$ 2,013
Regulatory related costs	806	1,150
Software acquisition & maintenance	1,202	1,090
Non-regulated	(5)	
Total Professional Services	**$ 5,318**	**$ 4,253**

(Grant Thornton 2003 General Rate Hearing Report, pg. 44; Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, pg. 6)

The higher costs in the professional services category for 2002 related primarily to the business process improvement project. This initiative alone accounted for $1,010,000 in consulting fees in 2002, which are not included in the 2004 Professional Services expense. (Grant Thornton 2003 General Rate Hearing Report, pg. 45) NLH has estimated external regulatory costs of $1,200,000 for the Board and the CA related to the current hearing. NLH requested that any additional costs as a result of the Board awarding costs be added to this total. NLH also proposed that these costs be amortized over a three year period beginning in 2004, consistent with prior hearings. (Final Argument, NLH, pgs. 89/10-30; 90/1-4)

The forecast 2004 travel expense of $2,395,000 is 3.5% higher than the 2002 actual. This category also includes conference travel ($217,000) and training ($256,000), which have been moved from Miscellaneous-Training in the revenue requirement to Travel. Excluding conference travel and training, travel expense has decreased from $2,213,000 in 2002 to a forecast of $1,922,000 in 2004. Grant Thornton indicated this is as a result of NLH's adoption of the RCM program, its initiative to use less internal staff for capital projects and the completion of two major capital projects. (Grant Thornton 2003 General Rate Hearing Report, pg. 46/5-15; Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, pg. 6/Notes 21; 23)

NP noted that the transfer of travel costs related to training, to be now charged directly to Travel, has resulted in a net reduction for 2003 of $271,000. NP suggested this same reduction in expense should be carried forward into the 2004 test year as a reduction in travel costs of $300,000.

NLH submitted that it has provided its best estimate of training and there is no evidence to support the recommendation that the associated travel expense should be decreased. (Transcript, Jan. 16, 2004, pg. 35/16-25)

Office supplies expense is consistent from 2001 to the 2004 test year forecast with no significant variances. (Grant Thornton 2003 General Rate Hearing Report, pg. 47/20-21)

Insurance expense has increased from $949,000 in 2001 to $2,019,000 in the 2004 test year, an increase of 113%. (NP-260) Mr. Roberts indicated that a restricted market is contributing to significant increases in insurance costs. (Pre-filed Evidence, J. C. Roberts, pg. 4)

In addition, NLH adds gross assets of approximately $35,000,000 a year, which require insurance coverage. (Grant Thornton 2003 General Rate Hearing Report, pgs. 46/25; 47/3-8)

The forecast equipment rentals expense of $1,756,000 for 2004 is 28% over 2002 actuals, due mainly to the increasing costs of leasing communication circuits, internet connection and licensing. (Grant Thornton 2003 General Rate Hearing Report, pgs. 46/25; 47/27-33; Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, pg. 6/9-10)

The forecast building rentals and maintenance expense of $894,000 is consistent with the 2002 actual experience. (Grant Thornton 2003 General Rate Hearing Report, pg. 46/25)

With respect to NP's submission that the 2004 test year travel expenses should be reduced by $300,000, the Board notes that the reduction in 2003 resulted from updated figures included in the revised October 31, 2003 filing and not the transfer of expense from one account to the other. The Board is satisfied that NLH's forecast of travel costs related to training is reasonable and justified.

The Board acknowledges NLH's request that any additional costs as a result of the Board awarding costs in this Decision and Order be added to NLH's estimate of regulatory costs to be amortized over a three year period. While the final costs of this hearing, including any cost awards, will not be finalized prior to this Decision and Order, the Board will allow an increase in the total regulatory costs of $600,000 to cover any additional costs, including cost awards, which may be incurred over and above the $1,200,000 estimated by NLH. While the Board acknowledges that this amount may or may not cover the full costs, in the interest of fairness and regulatory efficiency, the Board is satisfied that this amount is reasonable and will allow for substantial recovery of these costs by NLH. The Board will allow NLH to increase its regulatory costs by $600,000 with the total regulatory costs to be amortized over a three year period as proposed by NLH.

No other specific issues were raised by the intervenors. The Board accepts the Other Cost Categories as reasonable and justified.

The Board accepts NLH's 2004 test year expenses for travel, office supplies, insurance, equipment rentals and building rentals and maintenance, totalling $8,977,000.

The Board will allow an increase in the 2004 test year professional services expense of $200,000 to reflect the amortization over a three year period of additional regulatory costs.

6. Loss on Disposal of Capital Assets

NLH's forecast for loss on disposal of capital assets in the 2004 test year is $1,266,000, which includes an amount of $725,000 for the costs associated with the abandonment of the Davis Inlet diesel plant. (Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, pgs. 1; 6/Note 24) NLH is presently serving customers in Davis Inlet and in the new community of Sango Bay (Natuashish), where NLH is providing management services on behalf of the Federal

Government. Once all the residents of Davis Inlet have relocated to Natuashish, NLH will be removing its assets from Davis Inlet.

In supplementary evidence (pg. 7) Grant Thornton stated the increase in the loss on disposal of capital assets of $725,000 due to the projected discontinuance of service to Davis Inlet is unusual and not recurring in nature. Grant Thornton suggested it would be inappropriate to include an unusual item such as this in a test year revenue requirement being used to set rates for the coming years. Grant Thornton recommended that this cost be amortized over a three to five year period to normalize the 2004 test year forecast.

NLH pointed out during cross-examination of Mr. Brushett that, upon review of the decommissioning activities of NLH over the past several years, the amount forecast for the 2004 test year did not appear to be unusual. Mr. Brushett acknowledged that NLH has decommissioned a number of facilities over the years but stated that his reason for recommending the amortization of the expense over three to five years was to minimize the impact on rates in the test year. (Transcript, Dec. 11, 2003, pg. 29/14-20)

NP pointed out that in the 1995 Rural Rate Inquiry NLH indicated that it would insist on Federal Government funding for NLH's incremental capital costs in relation to the relocation of the community of Davis Inlet. Mr. Roberts testified that, although the Federal Government contributed to the cost of the new generating plant at Natuashish, it would not reimburse NLH for the loss on disposal of capital assets resulting from the decommissioning of the Davis Inlet plant. (Transcript, Nov. 12, 2003, pg. 124/7-10) NP argued that the contribution of the Federal Government to the cost of the new plant at Natuashish would result in reduced depreciation and interest expense for NLH in future years. NP agreed with Grant Thornton's recommendation and submitted that the Board order the amortization of this amount over a five year period. (Brief of Argument, NP, pg. B-41)

In final argument (pg. 41) NLH submitted that, given that there have been significant disposals of diesel plants by NLH and the fact that the average loss on disposals for the past five years is higher than the 2004 forecast loss (including the loss for the disposal of the Davis Inlet plant), it is difficult to see how one can conclude that the costs associated with the abandonment of Davis Inlet are unusual. NLH argued that the full costs of decommissioning the Davis Inlet plant should be included in the 2004 test year.

There were no other issues raised by the intervenors with respect to this expense category.

The Board agrees with NLH that the loss on disposal of assets relating to the decommissioning of the Davis Inlet plant is not unusual in itself when compared to previous years' losses on disposal resulting from plant closures. The Board also notes that the 2004 test year expense of $1,266,000 associated with the loss on disposal of capital assets (including Davis Inlet decommissioning costs) is significantly lower than the average loss on disposal since1998. NLH has decommissioned a number of facilities since 1998, including Southeast Bight and Mud Lake in 1998, LaPoile in 1999, Harbour Deep in 2002 and Petites in 2003. (Transcript, Dec. 11, 2003, pgs. 23-24) Given this recent experience and the fact that the average loss on disposal of assets for the past five years is higher than the 2004 forecast loss the Board accepts the test year expense as forecast by NLH as reasonable. The full costs of decommissioning the Davis Inlet Plant will be included in the 2004 test year costs.

The Board accepts NLH's 2004 test year expense of $1,266,000 for loss on disposal of capital assets.

7. Capitalized Expenses

Expenses associated with capital projects, such as salaries and benefits of NLH employees who are working on capital projects and related departmental and non-departmental overhead, are capitalized and then credited to the proposed revenue requirement. (Grant Thornton 2003 General Rate Hearing Report, pg. 49/21-22) NLH is forecasting that the capitalized expense credit for the 2004 test year will be $5,200,000. (Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003)

The following table is a breakdown of NLH's capitalized expense since 2001:

Capitalized Expenses - 2001 to 2004					
	2001	**2002**	**2002 Test Year**	**2003 Forecast**	**2004 Forecast**
Salaries	$8,977,207	$8,116, 250	$5,722,500	$7,913,000	$5,204,951
Fleet Expense	473,546	485,670	300,000	400,000*	300,000*
Travel direct work orders	115,693	21,341	108,640		
Total	**$9,566,446**	**$8,623,261**	**$6,131,140**	**$6,805,373**	**$5,503,951**

*From Grant Thornton's 2003 General Rate Hearing Report – not confirmed or updated in NLH's evidence
(Grant Thornton 2003 General Rate Hearing Report, pg. 49; Revised Evidence, J. C. Roberts, Schedule II, Oct. 31, 2003, pgs. 4/Note 13; 5/Note 25)

In Order No. P. U. 7(2002-2003) the Board acknowledged that a review of the methodology and approach used by NLH to determine capitalized expenses would be appropriate. However, because of the many other regulatory issues to be dealt with at that time the Board did not require NLH to undertake such a study. Mr. Roberts explained the methodology used by NLH to allocate expenditures to capitalized expense, and stated the estimate will vary in any given year depending on the utilization of NLH's internal resources. (Transcript, Oct. 14, 2003, pgs. 146-151)

NP-19 indicated that NLH's capitalized expenses as a percentage of capital expenditures from 1998 to the 2004 test year have ranged from 7% to 19%. The forecast capitalized expenses for 2003 and 2004 are 18% and 16% of capital expenditures respectively (based on NLH's May filing), which Grant Thornton found to be reasonable when compared to prior years. (Grant Thornton 2003 General Rate Hearing Report, pg. 50/16-18) Mr. Brushett testified, however, that it is appropriate for the Board to look at NLH's past experience in terms of the impact that capitalized expenses have had upon determining revenue requirement. (Transcript, Dec. 11, 2003, pg.116/15-23)

Mr. Roberts agreed that NLH's estimates of capitalized expense have varied by an average of approximately $2,900,000 between 1998 and 2002. (Transcript, Oct. 14, 2003, pg. 144/7-20) In Information #25 NP indicates that over the period 1998 to 2002 NLH's budgeted capitalized expenses have varied by an average of $2,200,000 compared with actuals. The difference in the two averages is that Information #25 includes an adjustment for capitalized overtime.

NP stated that under-estimating capitalized expense in the test year results in an increase in forecast net operating expenses and test year revenue requirement while increasing earnings to NLH when higher actual capitalized expenses are recorded. NP submitted that, considering NLH's estimating experience since 1998, it would be appropriate for the Board to increase NLH's forecast capitalized expense for the 2004 test year by $2,000,000. (Brief of Argument, NP, pgs. B-33 to B-35)

The other intervenors did not put forward a position on the matter of NLH's capitalized expenses.

In final argument (pg. 38) NLH suggested that, while there may be evidence the actual capitalized expense has exceeded the budget in previous years, the revised October 31, 2003 forecast for the 2004 test year was based on the knowledge of the approved capital budget and the internal resources to be used in completing that budget. NLH argued, in these circumstances, it would be inappropriate to make an arbitrary adjustment to the capitalized expenses forecast for 2004.

Considering the historical level of capitalized expense and the variance with forecast, the Board is satisfied that an increase of $2,000,000 in NLH's capitalized expense forecast for the 2004 test year is warranted.

With respect to the methodology for capitalizing expenses, the Board notes that the full-cost method currently used by NLH to capitalize general expenses to capital assets is different than the incremental method used by NP and approved by the Board in Order No. P. U. 3(1995-96). Both methodologies, in the Board's view, conform to generally accepted accounting principles. In this Decision the Board has adjusted NLH's capitalized expenses to reflect actual experience. There is no evidence before the Board that the full-cost approach does not continue to be an appropriate methodology. The Board will not direct a review of the methodology used by NLH to determine capitalized expense as contemplated in Order No. P. U. 7(2002-2003).

The Board will direct NLH to increase its 2004 test year capitalized expense by $2,000,000.

8. Non-Regulated Operations and Inter-Company Charges

Non-regulated operations are all costs associated with any asset which is not used and useful in the generation, transmission and distribution of electrical power, energy activities exempted by specific legislation, and costs specifically identified by the Board as being non-recoverable from ratepayers. Inter-company charges are those costs that NLH recovers for the provision of services to CF(L)Co. Expenses associated with non-regulated operations and inter-company charges are deducted from NLH's expenses to determine the regulated revenue requirement. For the 2004 test year NLH has reduced its revenue requirement by $1,858,000 for charges to CF(L)Co and $2,684,000 for non-regulated operations.

In Order No. P. U. 7(2002-2003) the Board directed NLH to file, on or before December 31, 2002, the written policies and procedures to account for all intra- and inter-corporate transactions, identifying what is to be included in regulated and non-regulated activities as a normal reporting function. The report was submitted in December 2002 and filed in this hearing as Exhibit JCR-2. The Board also ordered NLH, for the purpose of regulatory reporting, to file separate financial statements for regulated and non-regulated activities, including reconciliation with annual consolidated financial statements. NLH has complied with this requirement.

Grant Thornton reviewed the report during its 2002 Annual Financial Review and concluded that NLH had appropriately identified and defined its various non-regulated operations and had established appropriate procedures for recording and reporting these activities. (Information #3, pgs. 33-34)

The methodology used by NLH for determining inter-company charges was reviewed by Grant Thornton in its 2003 General Rate Hearing Report (pgs. 48-49) and no concerns or issues were noted.

The only issue with respect to this expense category was raised by the IC regarding NLH's practice of adding back non-regulated expenses to equity, which increases the equity and the actual dollar return to NLH. Mr. Brushett, in response to questioning from the IC, agreed that there is a counter-argument to NLH's method of dealing with these expenses that suggests they should be charged to the shareholder. Mr. Brushett added that logically, if the shareholder has been denied both a return and the expense, it could be deemed a double penalty. (Transcript, Dec. 11, 2003, pg. 143/11-20)

In final argument (pg. 16) the IC submitted that NLH's practice treats the monies as if they had not been spent at all, thus allowing NLH a return on these funds which it had already applied to its own, or its shareholder's purposes. This practice, the IC argued, is not justified and the Board should disallow it.

NLH submitted that its practice is consistent with regulatory practice in this jurisdiction and that such treatment has been consistently approved by the Board for NP. (Transcript, Jan. 16, 2004, pg. 37/10-19)

The other intervenors made no submissions on this issue.

The Board notes that this is essentially the same issue raised during NP's general rate hearing in 2003. NLH raised this issue at that time and put forward arguments with respect to using *"book equity"* versus *"regulated equity"* in measuring return on equity. Regulated equity is derived by adding to book equity the cumulative non-regulated expenses of the utility. In Order No. P. U. 19(2003) the Board acknowledged that the arguments with respect to using book equity have considerable merit. The Board directed NP to address the issue of discontinuing the use of regulated common equity in favour of book equity no later than its next general rate application. In the interest of consistency in regulatory practice the Board will direct the same for NLH.

The Board accepts NLH's treatment of non-regulated expenses and inter-company charges in determining its 2004 test year revenue requirement.

The Board will direct NLH to file a report on the appropriateness of discontinuing the use of regulated equity in favour of book equity as part of its next general rate application.

9. Interest Expense

The forecast regulated interest expense for the 2004 test year is $98,165,000, calculated as follows:

2004 Test Year Regulated Interest Expense (000's)		
Interest on short-term promissory notes and long-term debentures		$108,295
Add:	**Amortization of foreign exchange loss**	2,157
	Amortization of debt discount and issue expense	915
	Debt guarantee fee	14,684
		126,051
Less:	**Interest on sinking fund assets**	8,520
	CF(L)Co share purchase debt	2,116
	Financing charges – Rate Stabilization Plan	12,065
	Interest on overdue accounts	292
	Allowance for funds used during construction	4,892
	Interest on assets not in service	1
	Total	**$98,165**

(PUB-194; Revised Evidence, J. C. Roberts, Schedule VII, Oct. 31, 2003)

The Province guarantees NLH's debt and receives an annual fee equivalent to 1% of the previous year's debt net of sinking funds. The intervenors did not raise any issue with respect to the amount of the guarantee fee paid by NLH and included in the interest expense of the 2004 revenue requirement. In its discussion on capital structure and ROE, the Board acknowledged the importance of the guarantee fee in ensuring NLH's creditworthiness and accepted the level of the guarantee fee as reasonable.

NLH's revised evidence dated October 31, 2003 reflects a reduction in forecast short-term interest rates in the 2004 test year from an average of 5.0% to 2.78% resulting in a reduction in the interest expense of $3,550,000. There was also an increase of $23,000,000 in forecast promissory notes primarily due to higher forecast borrowing requirements in 2003.

These increased borrowing requirements were identified as being comprised primarily of increased fuel expense, lower proceeds from long-term debt issues and changes in non-cash working capital. (Revised Evidence, J. C. Roberts, Schedules II; V, Oct. 31, 2003)

In final argument NP took issue with the unexplained use of the accounts payable as a balancing number in determining borrowing requirements that could not be explained to its satisfaction by Mr. Roberts. NP also referred to the evidence of Mr. Brushett, who acknowledged that NLH's use of accounts payable as a balancing number would almost seem contrary to standard practice. (Brief of Argument, NP, pg. C-5; Transcript, Dec. 11, 2003, pg. 119) NP argued that the Board should order a $278,000 reduction in NLH's 2004 interest expense based on the unexplained and unjustified decrease in forecast accounts payable for 2003 and 2004, and impacts on short-term promissory notes and test year interest expense. (Brief of Argument, NP, pg. C-6/5-8)

Mr. Roberts stated during cross-examination that the accounts payable number is simply a balancing number applied to the balance sheet and it has no other significance. (Transcript, Nov. 12, 2003, pgs. 114-117) NLH argued that satisfactory answers were provided in responses to requests for information and through cross-examination in respect of all the issues raised by the intervenors and submitted that the interest expense as proposed by NLH for the 2004 test year should be approved. (Final Argument, NLH, pg. 25/5-25)

The Board acknowledges that the evidence is confusing as it relates to the forecast balances for accounts payable and the potential impact on the forecast borrowing requirements for 2003 and 2004. The explanation provided by Mr. Roberts did not clarify this issue for the Board. However, there is evidence that the treatment of accounts payable has been reviewed and justified recently as part of the Business Improvement Process. (Transcript, Oct. 14, 2003, pg. 101/14-17; Jan. 16, 2004, pg. 21/18-22) In addition the calculation of an expense lag in the working capital allowance calculation requires appropriate review of expenditures both when incurred and paid. While there is lack of clarity with respect to the accounts payable explanation, the Board is satisfied that NLH has appropriately estimated this amount and does not feel that the evidence supports a reduction in the forecast interest expense as proposed by NP.

The Board accepts NLH's 2004 test year interest expense, subject to any adjustments arising from this Decision and Order.

10. Productivity Allowance

Order No. P. U. 7(2002-2003) imposed a reduction in NLH's 2002 test year revenue requirement in the form of a productivity allowance in the *"Other Costs"* category of expenses, in the amount of $2,000,000. In deciding on the productivity allowance the Board stated:

> *"The Board has no level of comfort regarding individual cost savings or efficiencies and the Board is left with little choice in keeping with the least cost power policy of the Province but to impose an appropriate productivity allowance as suggested by GT and the intervenors."*

Mr. Wells suggested that for the Board to impose a productivity allowance for the 2004 test year would *"..only operate as a disincentive and a penalty"* in light of the continuous improvement process that NLH now has in place to measure performance throughout the organization. (Transcript, Oct. 6, 2003, pg. 33) Mr. Wells explained that the business improvement process was initiated in early 2002 by the retention of consultants to provide initial impetus and expertise on methods employed to review business processes. The consultant was identified by Mr. Wells, in cross-examination by NP, as Covenco, a firm from Ontario which was retained at a cost of $1,000,000. (Transcript, Oct. 7, 2003, pg. 75)

NP argued that, given NLH's performance since its 2001 general rate application and NLH's current operating characteristics, the Board should exercise its regulatory judgement in determining what is an appropriate productivity allowance for NLH. NP noted the Board may wish to consider a number of items in relation to a productivity allowance, including increases in 2004 test year costs, prior staff reductions realizing salary savings in 2004, confusion surrounding use of FTE's and difficulty in estimating savings attributable to business process reviews. NP submitted a productivity allowance of $2,000,000 remains appropriate for NLH in setting its 2004 test year revenue requirement. (Brief of Argument, NP, pgs B-32/6-24; B-33/1-5)

The CA indicated that the Board should look to the rate of return first and foremost. If the low rate of return is provided, the CA submitted there is no need for a productivity allowance. (Transcript, Jan. 16, 2004, pg. 63/16-23)

The IC argued that the considerations which led to the Board imposing a productivity allowance in Order No. P. U. 7(2002-2003) apply even more forcefully today by reason of NLH's position that its business process improvement project has decreased and will continue to decrease NLH's costs. The IC concluded that the productivity allowance should be in the range of $5,000,000. (Written Argument, IC, pg. 15)

When questioned during the course of the hearing on what efficiencies were achieved in implementing the productivity allowance, NLH stated that the Board gave no specific direction as to which expenditures were to be reduced. (Pre-filed Evidence, J. C. Roberts, pg. 2/24-25) This was confirmed in the testimony of Mr. Wells who stated in cross-examination by the IC that:

> A. (Mr. Wells) ...the Board at the time of making the order with respect to productivity allowance, didn't know exactly whether that would be going into a group of costs that really could take that productivity allowance, or whether they could not. It was not a precise thing. It was just an approach that was intended to send a message to Hydro that we have to be able to explain, to their satisfaction, where we are on performance. And they didn't break it down as to whether it was salaries and fringe benefits, system equipment maintenance or insurance and other costs....
>
> (Transcript, Oct. 9, 2003, pgs. 118-119)

Mr. Wells went on to explain that when Order No. P. U. 7(2002-2003) was issued NLH was halfway through its year and its plans were in place.

Grant Thornton noted the Board gave NLH the discretion to allocate this productivity allowance among the various expenditure categories. However, in order to expedite finalization of the 2003 revenue requirement, NLH presented the $2,000,000 allowance as a separate line item in the 2002 final test year forecast. (Grant Thornton 2003 General Rate Hearing Report, pg. 37/25-30)

The Board remains uncertain as to the impact on NLH of the $2,000,000 productivity allowance ordered in Order No. P. U. 7(2002-2003). The Board does not accept the implication by NLH that the productivity allowance was treated in the way it was because the Board was not more prescriptive in how expenditures were to be reduced. The Board believes such specificity would be an encroachment on the management of NLH. While the Board allowed NLH the discretion to allocate this productivity allowance, it does not exonerate NLH from the reasonable regulatory expectation of demonstrating to the Board in its Application what efficiencies were generally achieved.

The Board acknowledges NLH's effort with respect to the business improvement process initiated in 2002 and described by Mr. Wells in testimony as set out above. However, it is not clear from the evidence how the results of the business improvement process will result in long term savings and productivity gains for the various aspects of NLH's operations. In reviewing the record the Board notes the following:

- There was no description of Covenco, its qualifications, experience or reputation in the business management field offered by NLH;
- Covenco did not provide any written reports to NLH;
- there were no written terms of reference provided to Covenco; and
- there were no targets established in respect of the cost benefits to NLH as a result of Covenco's engagement.

From the Board's perspective the outcome of this initiative remains uncertain and the fact that the process is continuing is insufficient reason in and of itself to reject a productivity allowance. Grant Thornton suggested during the hearing there was considerable evidence put before the Board respecting the topic of key performance indicators (KPIs) and a number of related topics including operating efficiencies, business process improvements initiatives and a productivity allowance. Grant Thornton observed that all these topics are related and should be viewed that way from a regulatory perspective. Grant Thornton concluded KPI targets for 2004 have not been established and a more transparent linkage between process improvement initiatives and the key performance measures may assist the Board in effectively monitoring NLH's operating performance and efficiency. (Supplementary Evidence, Grant Thornton, Dec. 5, 2003, pgs. 1/11-17; 1/28-30; 2/1-3)

With a view to the 2004 test year revenue requirement, the Board has assessed each line item in rendering its determinations. The Board is also cognizant of the financial impacts on this revenue requirement of its decision on ROE. The Board will not impose a productivity allowance for the 2004 test year and accepts NLH's argument that to do so would operate as a disincentive and a penalty in light of measures being put in place to monitor and report on productivity and performance. In accepting this argument, however, the Board shares the view expressed by Grant Thornton that issues involving KPIs, business improvement processes and productivity are all related and should be dealt with in that way from a regulatory perspective. With this in mind the Board has considered productivity/efficiency as part of an integrated perspective on Regulatory Oversight – Planning, Performance Measure and Reporting contained in Part II - Section X of this Decision and Order.

The Board will not impose a productivity allowance for NLH's 2004 test year revenue requirement in light of other decisions taken in this Decision and Order.

IV. RATE STABILIZATION PLAN

1. Introduction

The Rate Stabilization Plan (RSP) is established for two of NLH's customers – NP and the Island Industrials – to smooth rate impacts for certain variations between actual results and test year COS estimates for (i) hydraulic production, (ii) No. 6 fuel cost used at NLH's Holyrood generating station, (iii) customer load (NP and Island Industrials), and (iv) rural rates. Issues surrounding the RSP were canvassed extensively during NLH's 2001 general rate hearing and the Board made a number of findings and orders regarding the RSP in Order No. P. U. 7(2002-2003).

2. Order No. P. U. 40(2003)

On December 16, 2003 the Board issued Order No. P. U. 40(2003) (Appendix J) approving amendments as of January 1, 2004 to the RSP with respect to the current rules in the existing rates schedules as well as recovery of historic plan balances. The only outstanding issue that was not addressed in the Order is ongoing monitoring of the RSP.

3. Ongoing Monitoring

Since the changes to the RSP increase the level of complexity of the plan and may cause increased volatility in rates, Grant Thornton suggested that the Board consider the appropriate reporting requirements to permit effective monitoring, including the impact on customers. (Supplementary Evidence, Grant Thornton, Dec. 5, 2003, pgs. 4-5) NLH acknowledged that the modified RSP may result in more volatility in customer rates. (Supplementary Evidence, S. D. Banfield, Nov. 21, 2003, pgs. 6/26-31; 7/1-3) Grant Thornton recommended that NLH be directed to undertake a review of the new plan after a 24-month period. This review should assess the effectiveness of the new plan along with customer impact and reaction, and determine whether any modifications are appropriate. (Supplementary Evidence, Grant Thornton, Dec. 5, 2003, pgs. 4-5)

The Board agrees that ongoing monitoring of the RSP is necessary to ensure that the plan is operating as intended in light of the changes approved in Order No. P. U. 40(2003). The Board also agrees with the recommendation of Grant Thornton that the RSP should be comprehensively reviewed after a 24-month period. As part of its ongoing regulatory supervision the Board may address additional reporting and review requirements for NLH's quarterly regulatory and annual reports. NLH will also be required to undertake a review of the operation of the RSP for the period January 1, 2004 to December 31, 2005. This review should assess the effectiveness of the revised RSP, including an assessment of the impact on customers in terms of rates based on the outstanding plan balance as of December 31, 2005.

The Board will direct NLH to complete a review of the operation of the RSP for the period January 1, 2004 to December 31, 2005. A report on this review setting out an assessment of the impact on customers should be filed with the Board no later than June 30, 2006.

V. RATE BASE

1. Fixing and Determining Rate Base

NLH's rate base is comprised of net capital assets in service, fuel inventory, supplies inventory, deferred foreign exchange losses and rate hearing costs, as well as an allowance for cash working capital.

In Order No. P. U. 21(2002-2003), arising from Order No. P. U. 7(2002-2003), the Board fixed and determined NLH's forecast test year rate base for 2002 at $1,359,570,000 and allowed a return on rate base for NLH based on the 2002 test year of 7.081%. NLH's average realized rate base for 2002 was $1,356,207,000. (Revised Evidence, J. C. Roberts, Schedule III, Aug. 12, 2003, pg. 1) In its 2002 Annual Financial Review of NLH Grant Thornton confirmed that the calculation of average rate base for 2002 is in accordance with established practice and Order No. P. U. 7(2002-2003). (Information #3, pg. 5)

Although NLH did not request in its Application that the Board fix and determine the 2002 rate base pursuant to Section 78 of the *Act* this would be considered normal regulatory practice. Grant Thornton also suggested that since this is the first time that NLH's actual rate base will be fixed and determined, the Board should consider whether a valuation of the rate base pursuant to Section 64 of the *Act* would be appropriate or necessary. (Grant Thornton 2003 General Rate Hearing Report, pg. 22/3-5)

In response to PUB-110 NLH submitted that the legislative direction found in subsection 17(2) of the *Hydro Corporation Act,* stated below, precludes and obviates a valuation of its rate base under Sections 64 and 68 of the *Act*:

> *"(2) For all purposes of the Public Utilities Act, the rate base of the corporation shall include the property and assets of the corporation at their net book value but excludes investments in subsidiaries of the corporation."*

NLH stated that it followed this provision in its 2001 general rate application when it first applied for approval of its rate base and is following this provision again in this Application.

Board Hearing Counsel suggested an alternative interpretation of Section 17(2) of the *Hydro Corporation Act* could lead to the conclusion that those assets which are deemed to be used and useful are to be added at their net book value as opposed to some other measure, such as original cost. This alternative interpretation of Section 17(2) would require NLH to demonstrate that an asset is used and useful prior to its being added to the rate base. Finally Board Hearing Counsel pointed out that, regardless of the interpretation of Section 17(2), it is necessary to fix and determine NLH's rate base effective on commencement of the regulation of the utility and that all subsequent additions to plant can then be reconciled to this starting point. (Final Submission, Board Hearing Counsel, pg. 20)

The intervenors did not make submissions on NLH's argument regarding the valuation of its rate base and the applicability of Section 17(2) of the *Hydro Corporation Act.*

Pursuant to Section 80 of the *Act* a utility is entitled to earn a fair return on the rate base as fixed and determined by the Board. One of the primary responsibilities of the Board is to fix the amount of the rate base on which a utility is entitled to earn a return. As the amount of the rate base is the basis for the rate of return the determination of the rate base is a fundamental part of the regulation of the utility. A relatively small change in the rate base can significantly impact revenues which are collected from customers. The Board therefore must always be cognizant of its mandate with respect to the determination of rate base.

The rate base is fixed and determined by the Board pursuant to Section 78 of the *Act* and includes the property and assets of the utility as determined by valuation plus other specific amounts allowed by the Board. The valuation is conducted pursuant to Section 64 of the *Act*, which allows the Board to inquire into and determine the extent, condition and value of the whole or a portion of the property and assets of a public utility used and useful in providing or supplying a particular service to or for the public. The Board notes that in the late 1950's and early 1960's the Board conduced a valuation prior to fixing and determining the property and assets of NP or its predecessor companies.

As set out earlier, NLH argued in PUB-110 that Section 17(2) of the *Hydro Corporation Act "precludes and obviates"* a valuation of NLH's rate base. The Board does not agree. Section 17(2) does not *"preclude"* the Board from conducting a valuation under Section 64. The *Act* gives the Board the clear authority to conduct a valuation and nothing in subsection 17(2) prevents the Board from conducting this valuation. The difficult question is whether Section 17(2) *"obviates"* or makes unnecessary a valuation under Section 64. That would be the case if in all instances Section 17(2) requires all the property and assets of NLH as determined by NLH to be included in the rate base at their net book value. The Board is not satisfied that this Section goes this far.

The Board concludes that, given the importance of the rate base to the regulatory process, the Board must have jurisdiction to determine the components and value of the rate base to the extent that the language of Section 17(2) will permit. The Board notes Section 118(2) of the *Act* which states that the Board shall have all the powers necessary and incidental to carry out the powers specified in the *Act*. The Board concludes that the language of Section 17(2) of the *Hydro Corporation Act* leaves jurisdiction with the Board to carry out its mandate with respect to the review of the rate base. For example, the provision does not say that *"all"* of the property and assets as determined by NLH shall be included in the rate base. Rather it could be read to say that property and assets which are included in the rate base shall be included at their net book value. The provision seems to allow for circumstances where there may be property and assets which are recorded in the financial records but are not used and useful because they are obsolete or they cannot be found. An example of this scenario was presented in this hearing when NLH sought to write-off assets recorded in the financial records with a net book value of $800,000 which could not be matched to assets in the field. The Board therefore concludes that it has the authority to conduct a valuation under Section 64 of the *Act* with respect to the property and assets of NLH and further that there may be circumstances where the Board will find that such a valuation is necessary and appropriate.

While this issue was raised during the hearing, no party to this hearing suggested that a valuation was necessary or appropriate for the determination of the rate base. No evidence was presented to challenge the 2002 rate base as proposed by NLH.

Given the extensive effort and costs associated with conducting a valuation under Section 64, the Board finds that it is not appropriate to order a valuation in the context of little or no evidence to suggest that one is necessary and appropriate in the circumstances.

The Board notes that NLH advised during the hearing that it has undertaken a process review to match all the physical plant records to the equipment in the field. (Transcript, Oct. 16, 2003, pg. 61/15-20) Mr. Wells stated that this matching does involve some determination as to whether an asset is used and useful but that this is not the primary purpose of the review, which he indicated as being "*…to match financial records with equipment records and to identify any differences and make the appropriate adjustments if deemed necessary.*" (Transcript, Oct. 16, 2003, pg. 65/10-13) Once this review has been completed NLH should have a comprehensive up-to-date list of all of its property and assets. The Board views this effort as a necessary first step to consideration as to whether a valuation of the property and assets is necessary since it will match the financial and field records and detail the property and assets which should, in NLH's view, be part of the rate base.

Since this review should provide better evidence as to whether a valuation is necessary, NLH will be required to file with the Board no later than its next general rate application a report detailing the results of the process review of its property and assets. This report should set out a list of its property and assets, the acquisition date, the original cost, the purpose of the asset, the net book value and, where applicable, the load served. The Board will consider the issue as to whether a valuation of the property and assets of NLH is necessary and appropriate at NLH's next general rate application.

Given that there were no submissions or evidence challenging the 2002 rate base as proposed by NLH and that the Board's financial consultant confirmed that the accounts are in accordance with established practice, the Board finds that the 2002 rate base of $1,356,207,000 should be fixed and determined. Further given that there was insufficient evidence with respect to the necessity of a valuation and, in light of the fact that NLH is conducting a process review to match its financial and equipment records, the Board will require NLH to file a report as to its property and assets.

The Board will fix and determine the 2002 rate base at $1,356,207,000.

The Board will require NLH to submit, as part of its next general rate application, a report with respect to the review of its property and assets setting out the acquisition date, the original cost, the purpose of the asset, the net book value and, where applicable, the load served.

2. Forecast Average Rate Base and Return on Rate Base

The forecast average rate base for 2003 is $1,427,552,000 and for the 2004 test year the forecast average rate base is $1,483,381,000. (Revised Evidence, J. C. Roberts, Schedule III, Oct. 31, 2003, pg. 1)

The 2004 forecast average rate base is as shown below:

2004 Forecast Average Rate Base ($000)	
Capital Assets	$1,940,513
Less: Contributions in Aid of Construction	85,906
Accumulated Depreciation	494,881
Muskrat Falls Assets	2,010
Assets not in Service	74
Net Capital Assets	1,357,642
Net Capital Assets Previous Year	1,371,366
Average Capital Assets	1,364,504
Cash Working Capital Allowance	3,084
Fuel Inventory	14,520
Supplies Inventory	19,387
Deferred Realized Foreign Exchange Loss plus PUB Costs	81,886
Average Rate Base	**$1,483,381**

(Revised Evidence, J. C. Roberts, Schedule III, Oct. 31, 2003)

Grant Thornton reviewed the calculation of NLH's forecast average rate base for the 2004 test year and confirmed that the calculations are reasonable and appropriate in reference to legislative guidance, normal regulatory practice and existing Board Orders. (Grant Thornton 2003 General Rate Hearing Report, pg. 22)

There has been a net increase of $135,260,000 in average capital assets in service from 2002 to 2004, primarily due to the Granite Canal project ($134,550,000) and the 2003 and 2004 capital projects. (IC-257) This has been offset by reductions in average fuel and supplies inventory balances, cash working capital allowance and deferred charges balances. (CA-127; Revised Evidence, J. C. Roberts, Schedule III, Oct. 31, 2003)

NLH was also directed in Order No. P. U. 7(2002-2003) to provide a study of the implications upon cash working capital allowance of the timing difference between the payment of semi-annual long-term bond interest and the receipt of the funds for their payment. This report was filed in this proceeding. (Exhibit JCR-1) The report concludes that NLH's current method of forecasting interest expense and the cost of debt already reflects the timing of semi-annual interest payments and recommended continuation of the current methodology for the determination of NLH's cash working capital allowance. Both Grant Thornton and Ms. McShane supported NLH's recommendation that the current methodology for calculating the cash working capital allowance be continued. (Grant Thornton 2003 General Rate Hearing Report, pg. 22; Pre-filed Evidence, K. C. McShane, pgs. 3-4)

In final argument (pg. C-2) NP submitted that the Board should rely on the revised forecast average rate base of $1,483,381,000 in determining NLH's revenue requirement for the test year and, if the Board orders NLH to reduce its forecast capital expenditures, it should also require NLH to make the appropriate adjustments to its forecast average rate base.

NLH's return on rate base is calculated by applying its weighted average cost of capital (WACC) to its rate base, excluding rural assets, and its weighted average cost of debt to the rural assets component of the rate base. The inputs into WACC are described in Grant Thornton's 2003 General Rate Hearing Report (pg.16/2-6) as the average forecast capital structure and the forecast cost of the individual components of invested capital, both debt and retained earnings. The forecast return on rate base for 2004 is $116,829,000 or 7.88% calculated as shown below:

2004 Forecast Return on Rate Base ($000)				
Component Base	**2004**	**Weighted Average Cost of Debt**	**Weighted Average Cost of Capital**	**Return on Rate Base**
Rural Interconnected and Isolated Assets	213,447	6.852%		14,625
Other Rate Base Assets	1,269,934		8.048%	102,204
Average Rate Base	**1,483,381**			**116,829**

(Revised Evidence, J. C. Roberts, Schedule IV, Oct. 31, 2003)

NLH's rate of return on rate base from 2000 to 2004 was outlined in Grant Thornton's 2003 General Rate Hearing Report (pg. 21) as follows:

Rate of Return on Rate Base						
	2000	**2001**	**2002**	**Test Year 2002**	**Forecast 2003**	**Forecast 2004**
Rate of Return on Rate Base (%)	7.69	7.79	7.25	7.08	6.31*	7.88%**

* Revised Evidence, J. C. Roberts, Schedule III, Oct. 31, 2003, pg. 1
** adjusted as referenced above.

Grant Thornton concluded in its report (pg. 22/25-28) that NLH's calculation of the return on average rate base is in accordance with established practice and Order No. P. U. 7(2002-2003).

NLH submitted that its rate base and the return on rate base should be approved as filed, subject to any adjustments ordered by the Board for capital budget underspending and the Board's decision with respect to approval of additional capital expenditures requested by NLH on November 21, 2003. (Final Argument, NLH, pg. 50/7-10)

The Board is satisfied that the approach and methodology used by NLH in calculating its average rate base and return on rate base for the 2004 test year is appropriate. The Board accepts

NLH's proposals, subject to any adjustments required as a result of this Decision and Order and the Board's Order No. P.U. 5(2004) issued February 5, 2004 approving additional 2004 capital expenditures for NLH.

The Board will require NLH to file a revised calculation of rate base and rate of return on rate base for the 2004 test year which reflects the findings of the Board in this Decision and Order.

3. Range of Return on Rate Base and Excess Earnings Account

In the interest of regulatory consistency with NP, Grant Thornton recommended that the Board consider establishing an allowed range and upper limit of rate of return on rate base for NLH and instruct NLH to establish an *"excess earnings account"* to deal with any earnings generated in excess of the upper limit as prescribed. Grant Thornton addressed this issue in both its pre-filed (pg. 22/21-23) and supplementary (pg. 5/21-24) evidence. Grant Thornton suggested that, while the Board should assess this range in the context of its findings on other related financial matters, NP's range of rate of return may be an appropriate starting point for setting a range of return on rate base for NLH, which could be adjusted to reflect other Board decisions. (Supplementary Evidence, Grant Thornton, Dec. 5, 2003, pg. 5/26-30)

In commenting on Grant Thornton's evidence, NLH pointed out there was no evidence from any of the financial experts on an appropriate range of return on rate base and that it would be premature for the Board to accept these recommendations in advance of this Order. NLH argued it should be asked to provide its opinion on both the range of rate of return on rate base and on an excess earnings account once the Board has made its decision on the fair and reasonable return for NLH. (Final Argument, NLH, pgs. 50/24-30; 51/5-16)

NP suggested there is insufficient evidence to enable the Board to determine an appropriate range of rate of return on rate base for NLH, particularly when differences between the utilities may require a different range. NP submitted the preferable approach would be for the Board to deal with all related issues, including the range of return on rate base, an excess earnings account and an automatic adjustment formula when NLH brings forward an integrated financial proposal. (Brief of Argument, NP, pgs. C-20/13-22; C-21/16-18)

The IC did not support a range of rate of return on rate base but did support the establishment of an excess earnings account to be disposed of by direction of the Board either annually or upon achievement of a specific target amount. (Written Argument, IC, pgs. 11-12)

Board Hearing Counsel submitted that, whichever methodology is used to calculate NLH's cost of capital, the Board may wish to consider implementing an approved range of rate of return on rate base and excess earnings account which would function similarly to that used to regulate NP. Board Hearing Counsel observed this approach would provide NLH with some financial flexibility. (Final Submission, Board Hearing Counsel, pgs. 7/8-23; 8/1-4)

The Board agrees that little evidence was presented on the issue of range of return on rate base and an excess earnings account during the hearing but points out those have been in operation for quite some time in regulating NP. The Board clearly has the authority to deal with excess earnings of the utility and in that regard the authority to establish a range of return on rate base as well. The findings from the Stated Case support the Board's jurisdiction in this area. On the question of whether the Board has jurisdiction to set the rate of return as a range of permissible rates of return, the Court stated:

> *"[68] It is to be noted that s-s. 80(1) does not speak in terms of a "rate" or "rates" of return; rather, it speaks of a just and reasonable "return". It is not limited by its language to the pinpointing of a particular rate of return. I conclude that a liberal construction of the word "return" in the context of s-s. 80(1) leads to the conclusion that it can include a range of rates of return.*
>
> *[69] Of course, in applying the rate of return to the rate base, as ascertained by the Board, a single figure will have to be used since rates, tolls and charges are expressed as finite numbers. The Board in practice has chosen the mid-point of its stated range of rates of return as the figure to be used for this purpose. This is a perfectly acceptable practice for the purpose of setting the rates. By expressing a range, however, the Board leaves open to the utility the flexibility of earning more than the mid-point up to a maximum end of the range so as, in effect, to give the benefit of the doubt to the utility that the expert evidence favouring the upper end of the range turns out to be more accurate and to provide an incentive to the utility towards managerial efficiency."*

On the question of the scope of the Board's powers to deal with situations where a utility in fact earns a rate of return that is greater than that determined to be a just and reasonable return, the Court stated:

> *"[74] If, as determined in the answer to Question 1, the Board has jurisdiction flowing from s-s. 80(1) to prescribe the maximum rate of return which a utility may earn in a given year, it is a necessary consequence of such a determination that revenue earned in excess of the maximum of the prescribed range of return is excess revenue to which, by definition, the utility will not be entitled. The Board accordingly must have jurisdiction to regulate how that excess revenue is to be dealt with."*

Indeed, it may be argued that failure to establish a range of return on rate base and an excess earnings account would create uncertainty as to the treatment of any earnings in excess of the allowed rate of return ordered by the Board. The Board believes that eliminating any uncertainty by dealing with this issue now will promote stability and predictability for both ratepayers and NLH.

As noted above the Board has the authority and responsibility to deal with the disposition of any *"excess earnings"* generated by NLH. In this regard the Board has the flexibility to consider the facts and circumstances giving rise to the *"excess earnings"* and take these into consideration in ordering the disposition of same. The use of a range of return can be an incentive to NLH to seek efficiencies and productivity improvements that will benefit ratepayers through lower rates in the future. To the extent excess earnings may be generated from productivity initiatives the Board may consider this when dealing with the disposition of those excess earnings.

The Board concludes that a consistent approach with respect to using a range of rate of return on rate base and an excess earnings account is a practical and effective method of regulating both NLH and NP in the future. The determination of an appropriate range for NLH must be made within the context of NLH's Application, in particular its financial parameters (e.g. capital structure, ROE, WACC, interest coverage, etc.), and within the context of the Board's findings in this Decision and Order. However, the Board is not satisfied that there is sufficient evidence to set a specific range for NLH's return on rate base as of this Decision and Order and will require NLH to file a proposal for the Board's consideration.

As part of its revised filing of rate base and rate of return on rate base NLH will be required to file for the Board's consideration a proposal for a range of return on rate base and a definition of an *"excess earnings"* account. This proposal should include an analysis of several alternate ranges along with the associated impacts.

4. Automatic Adjustment Formula

The Automatic Adjustment Formula (AAF) is used by the Board to annually adjust NP's rate of return following the test year until its next general rate application. Grant Thornton recommended that, in the interests of regulatory efficiency and consistency with NP, the Board should also address whether implementation of an AAF is appropriate for NLH at this time. Grant Thornton also suggested that, if the Board finds that an AAF is appropriate, the Board should request NLH to file a proposal detailing how implementation could be achieved for 2005. (Supplementary Evidence, Grant Thornton, Dec. 5, 2003, pg. 6/6-14)

In its response to CA-169 and NP-105 NLH stated that an automatic adjustment mechanism may be appropriate at such time as the rate structure permits the indicated change in revenue requirement to be easily distributed across rate classes. In final argument, NLH submitted that no financial expert provided evidence on this issue but suggested the application of an AAF would be appropriate following the determination of an appropriate ROE for NLH. NLH proposed that the issues of a range of return on rate base and an excess earnings account be dealt with at the same time. (Final Argument, NLH, pgs. 51/24-27; 52/1-6)

The CA expressed concerns about the ability of the Board to monitor an AAF without the Board having the legislative jurisdiction to provide a remedy against over-earning on equity. The CA argued consumers would only agree to the construction of a formula, both for NP and NLH, if legislation is amended to move from rate base regulation to regulation based on equity; otherwise the Board should rescind use of any formula immediately. (Final Submission, CA., pg. 42)

NP commented that integrated proposals for dividend policy, capital structure, rate of return on equity, rate of return on rate base, range, excess earnings account and AAF are required to fully address the financial position of NLH. NP argued all of these items are important components in the regulation of NLH as a Crown owned utility. NP's preferred approach is to deal with the AAF, the range of return on rate base, and the excess earnings account based on an integrated proposal from NLH. (Brief of Argument, NP, pg. C-21/16-18)

In noting Grant Thornton's evidence, Board Hearing Counsel observed the AAF has applied to NP since 1998 and considerable effort was directed during NP's 2003 general rate application toward improving its operation. While certain lessons can be learned from the operation of NP's AAF, Board Hearing Counsel cautioned there was little direct evidence led during the hearing on how an AAF would be implemented in the context of NLH's financial parameters. Board Hearing Counsel concluded the Board could consider directing NLH to submit an AAF proposal by mid-2004 in order to allow ample time for its review by the Board's financial advisor and its implementation in the Fall of 2004. (Final Submission, Board Hearing Counsel, pgs. 8/6-20; 9/1-3)

The Board agrees that, in the interests of regulatory consistency and efficiency, an AAF should be considered for NLH. However, the Board is not satisfied that there is sufficient evidence as a result of this hearing to implement an AAF as of this Decision and Order. The Board notes that the existing formula to adjust the rate of return on rate base for NP was accepted and implemented by the Board following a full cost of capital hearing at which specific evidence regarding the appropriateness and the structure of an automatic adjustment mechanism was reviewed. The resulting formula adopted by the Board in Order No. P. U. 16(1998-99) reflects the complex relationship between rate of return on rate base and the cost of the various components of the capital structure of NP. In the Board's opinion such a mechanism to automatically adjust NLH's rate of return on rate base would be similarly complex and would have to be designed to reflect the costs specific to NLH. Given the uncertainty surrounding NLH's forecast capital structure over the short-term, and in light of the Board's decision with respect to the ROE to be used in rate setting, the Board is not convinced that it is necessary or that there are any clearly discernable benefits to be gained by putting an AAF in place as of this Decision. The Board does agree that, in the future, an AAF should be considered and NLH should submit a proposal at the time of its next general rate application for consideration by the Board.

The Board will not implement an automatic adjustment mechanism for NLH's rates at this time. NLH will be required to submit a report containing a proposal for such a mechanism with analysis as to the impacts for consideration at its next general rate application.

VI. COST OF SERVICE

1. Introduction

NLH filed its Application using the generic Cost of Service (COS) methodology recommended by the Board as a result of the 1992 generic COS hearing, as modified and finalized in Order No. P. U. 7(2002-2003). As directed by the Board NLH prepared separate COS studies for each of the five systems it serves: Island Interconnected; Island Isolated; Labrador Isolated; L'Anse au Loup; and Labrador Interconnected. NLH has confirmed that since its 2001 general rate hearing there have been no changes to any of the systems that would affect the COS studies, with the exception of the Island Interconnected System. The changes and additions to the Island Interconnected System affecting the COS study result primarily from reconstruction and upgrades of specific transmission assets and also from the addition of new generation capacity at Granite Canal, Abitibi Consolidated Company of Canada - Grand Falls, and at Corner Brook Pulp and Paper Limited. (Pre-filed Evidence, J. R. Haynes, pgs. 39-40)

In its Application NLH proposed three minor changes to the COS methodology:

1. Hydro Place costs should be assigned to all systems.
2. General plant assets should be functionalized on the basis of direct generation, transmission, distribution and customer expenses rather than plant ratios.
3. NLH's municipal taxes and Board assessments should be assigned the same functionalization and classification distribution as the sub-total of the COS for each class, excluding revenue-related.

The Mediation Report (Appendix H) identified the following COS issues as issues on which the parties agree:

" a. Hydro's cost of service (COS) study filed in this proceeding is in general compliance with Board Orders, specifically the June 7, 2002 Order No. P. U. 7(2002-2003), regarding the use of embedded cost of service studies as a guide in determining the revenue requirement increases or decreases to be applied to each class.
b. Hydro Place costs should be assigned to all systems as proposed by Hydro.
c. General plant assets should be functionalized on the basis of direct generation, transmission, distribution and customer expenses rather than plant ratios.
j. Hydro's Municipal Taxes and Board Assessments should be allocated based on revenues."

Although not raised by NLH in its Application, the following COS issues were identified as those on which the parties disagree:

"l. Should Burin Peninsula assets be assigned to common?
m. Should GNP generation assets be assigned to common?
o. What is the appropriate treatment of NP thermal Generation in Hydro's COS and rates charged to NP (e.g., NP Generation Credit)?"

The Board has reviewed the Mediation Report and the evidence filed with respect to COS issues on which there were agreement. The Board concludes the proposed changes to the COS methodology as agreed in the Mediation Report are reasonable.

The Board accepts the proposed changes to the COS methodology with respect to the assignment of Hydro Place costs, NLH's municipal taxes and Board assessments, and with respect to the functionalization of general plant assets.

The outstanding COS issues regarding plant assignment and the treatment of NP's generation are discussed below.

2. Assignment of Great Northern Peninsula, Burin Peninsula and Doyles -Port aux Basques Assets

The COS study filed in this proceeding assigns all generation and transmission assets of the Great Northern Peninsula (GNP), Doyles-Port aux Basques and the Burin Peninsula as ordered by the Board in Order No. P. U. 7(2002-2003). The GNP generation and transmission assets are specifically assigned to Hydro Rural, the Doyles-Port aux Basques transmission assets are specifically assigned to NP, and the Burin Peninsula transmission assets are assigned to common.

In Order No. P. U. 7(2002-2003) the Board made the following determination regarding the assignment of the GNP, Burin Peninsula and Doyles-Port aux Basques assets (pg. 113):

> *"Based on the evidence before it in this hearing the Board is not prepared to confirm the change in assignment from NLH rural to common of the generation and transmission assets on the GNP. The proposed change in the assignment of the Doyles-Port aux Basques assets from NP specifically assigned to common is also not accepted. The Board will require NLH to undertake the necessary studies and analyses to support the value of the interconnection of the GNP assets to the grid, including an assessment of the impacts on system reliability and the conditions and operating scenarios under which the GNP generation would be of benefit to the operation of the Island Interconnected system. This study should also review the value of the Doyles-Port aux Basques and the Burin Peninsula systems to the grid."*

NLH filed with its Application a study Review of COS Assignment for the GNP, Doyles-Port aux Basques, and Burin Peninsula Assets. (Exhibit JRH-3) NLH's COS expert Mr. Greneman summarized the conclusions of the study as:

- *"All generation assets on the GNP should be reassigned from rural to common since they act to enhance reliability of the system;*
- *Transmission assets related to the GNP and Doyles-Port aux Basques remain specifically assigned to Hydro Rural based on the fact that they are radial lines with generation of less than sufficient magnitude to justify their assignment to common;*
- *Transmission assets on the Burin Peninsula continue to be assigned to common as they serve more than one customer (NP and Hydro Rural)."*

Mr. Greneman stated that, based on his review of the report, the principles relied on are consistent with those commonly used in the industry to evaluate whether an asset should be treated as common or directly assigned. (Pre-filed Evidence, R. D. Greneman, pg. 10/18-21)

As the parties and experts have put forth differing opinions with respect to the outstanding COS issues the Board will consider each separately. While the Mediation Report does not identify the question of the cost assignment of the Doyles-Port aux Basques transmission assets as a point of disagreement, the Board will address this issue below since it was discussed in Order No. P. U. 7(2002-2003).

GNP Generation Assets

Based on the study undertaken, NLH proposed maintaining the following guideline for the assignment of its generation assets to common as proposed during its 2001 general rate hearing and all previous referrals before the Board. (Exhibit JRH-3, pg. 16):

"The following facilities will be assigned as Common Plant:
- *All of Hydro's production facilities (hydraulic, thermal, gas turbine and diesel)"*

Common plant is defined as plant that is of substantial benefit to more than one firm customer. Costs for common plant are assigned to all customers of the system. If the Board accepts NLH's proposal the assignment of the GNP generation assets will change from being specifically assigned to Hydro Rural as in the COS study to being assigned to common plant, with costs assigned among all customers.

In final argument NLH submitted that the evidence demonstrated that the generation on the GNP has been used to benefit customers on the Island Interconnected System. NLH also stated that if the GNP generation were not available to the Island Interconnected System the need for new capacity would be advanced from 2011 to 2009. If the Board determines that the GNP generation assets should be assigned as Rural, NLH suggested that consideration should be given to providing a generation credit to Hydro Rural customers, as is the case with NP. (Final Argument, NLH, pg. 57/25-30)

The IC disagreed with NLH's position with respect to GNP generation assets stating that, absent the GNP interconnection, the customers on the Island Interconnected System would have better reliability than they have today. To support this assertion the IC pointed to the evidence in IC-399, which shows the Loss of Load Hours (LOLH) and energy balance in the hypothetical scenario in which the GNP was not interconnected. Under this scenario the Island Interconnected LOLH and the energy balance would both improve and the requirement for future generation additions to the Island Interconnected grid would be delayed from 2010 until 2012. The IC stated in final argument (pg. 22):

> *"Despite this reduction in service quality by reason of the GNP Interconnection, the approach proposed by Hydro results in about $190,000 in extra costs to the IC group. This added cost to the Industrial Customers group as a result of a project that is designed to provide service to rural customers (at the expense of the Island Interconnected grid) is not appropriate and contrary to*

the provisions of the EPCA 1994 which prohibit charging Industrial Customers for the costs to serve rural customers."

The IC also argued that the appropriate test for allocation of resources to common versus specifically assigned is not simply *"do they provide benefits to the Island Interconnected customers"* but also *"what is the appropriate allocation to track the relative benefits received"*. The IC submitted that the evidence shows that the GNP generation is dispatched to primarily support the rural customers in the GNP area, stating: "*The frequency of the use of the GNP generation reflected in the evidence indicates that, since interconnection, the GNP generation has been commissioned 117 times (98% of the dispatch) for local support and back-up and 3 times for system support (2% of the dispatch).* NLH's allocation approach however results in NP and the IC being assigned over 90% of the costs of these units which, according to the IC, is not consistent with the principle of cost allocation tracking the benefits received. (Written Argument, IC, pg. 23) The IC submitted that: *"The GNP generation cannot be viewed to comprise a "substantial benefit" to customers other than the Hydro Rural customers for which this generation serves as local back-up so as to warrant common assignment and the corresponding additional costs of approximately $190,000 per annum to the Industrial Customers."*

NP submitted that all generation assets connected to the Island Interconnected System provide substantial benefit to the Island Interconnected System and agreed with NLH's proposal to assign GNP generation assets to common. In final argument NP stated that all generation assets on the Island Interconnected System benefit all customers by deferring capacity additions to the system, regardless of their location. As well NP submitted that recent events on the Island Interconnected System have demonstrated the benefits of the GNP generation in meeting system peak requirements and assisting system restoration efforts. (Brief of Argument, NP, pg. D-4)

The CA and EES Consulting both agreed with NLH's proposal to assign GNP generation as common plant.

In making its determination the Board finds the information presented in Table 3-2 and Table 3-3 of Exhibit JRH-3 particularly helpful. These tables compare the near term capability requirements for the Island Interconnected System with and without the GNP, Burin Peninsula and Doyles-Port aux Basques assets in the generation mix. When each of these generation assets is removed from the generation mix the timing of capacity deficits on the interconnected system is advanced by two to four years. The combined effect of removing all the assets advances the timing of capacity deficits from 2011 to 2004. The Board agrees with the conclusion stated in NLH's report "*…from a generation planning point of view the value of these assets is in their contribution to the overall reliability of the generation system with the resultant impact on resource decisions of the past, and as illustrated in Table 3-3, resource decisions yet to be made. This contribution is to the benefit of all customers on the Island Interconnected system."* (Exhibit JRH-3, pg. 13)

The generation assets on the GNP were originally constructed to serve the isolated system. With the interconnection of the GNP these generation assets now serve as reserve capacity to the interconnected system. NLH includes in its overall system planning all generation connected to the system and available to be used regardless of the location of the generation source. (Transcript, Oct. 20, 2003, pgs. 188/10-25; 189/2-9) While the Board agrees with the IC that the GNP generation is used primarily for back-up generation and voltage support for NLH's rural customers on the GNP, it cannot discount the fact that the generation has been used (although on an infrequent basis) to support the interconnected system at times of system peak. (Transcript, Oct. 20, 2003, pgs. 190-192) In the Board's opinion, this fact, combined with the impact of the GNP generation assets on the timing of new capacity, supports the assignment of this plant to common.

The Board accepts NLH's proposed assignment of the generation assets on the GNP as common plant.

GNP Transmission Assets

NLH proposed the following guideline in determining the cost allocation for transmission assets (Pre-filed Evidence, J. R. Haynes, pg. 43):

"The following facilities will be assigned as Common Plant:

- *All of Hydro's transmission and terminal station plant, 66 kV and above, that is of substantial benefit to more than one customer;*
- *All of Hydro's transmission and terminal station plant whose sole purpose is the interconnection of a generating facility with the system. Transmission and terminal station plant in this category have their costs classified on the same basis as the generation that it interconnects; and*
- *All of Hydro's transmission and terminal station plant that connects a single customer and generation or voltage control equipment, that is of substantial benefit to more than one customer."*

In interpreting this guideline NLH proposed that factors such as historical assignment, primary function, and quantity of generation be weighed in determining the ultimate assignment of the transmission and terminal station assets.

NLH stated that, while the GNP generation is recommended to be assigned as common, the generation is not of sufficient magnitude to justify the assignment of the GNP transmission assets to common, given the dominant use of the transmission system to serve NLH's rural customers. (Exhibit JRH-3, pg. 21) For this reason NLH proposed that the GNP transmission assets be assigned to Hydro Rural.

The IC and NP supported NLH's proposed assignment of GNP transmission assets. The IC pointed out in final argument (pg. 24) that assignment of GNP transmission assets to common would result in an additional $1,109,000 of costs being allocated to the IC.

EES Consulting stated that generation facilities and associated transmission facilities should be assigned in a similar manner, since the benefits of the generation cannot be delivered without the associated transmission facilities. (Pre-filed Evidence, EES Consulting, Sept. 19, 2003, pg. 19) EES Consulting recommended that, as all customers on the Island Interconnected System benefit from the generation facilities on the GNP, and given that they would not receive the benefit without the GNP transmission, the transmission facilities should also be assigned common.

In its 1995 report the Board stated "*...the Board is struck by the inconsistency in the proposed treatment whereby Newfoundland and Labrador Hydro treats generation assets as common but the related transmission line is treated as specifically assigned.*" EES Consulting raised a similar issue in this hearing. NLH addressed the issue of assignment consistency in its report and concluded that remote generation and the connecting transmission and terminal station assets could logically be assigned differently in the COS, as are the thermal generation of NP and its connecting transmission and distribution lines, and on the basis of the difference in planning criteria for generation and transmission assets. (Exhibit JRH-3, pgs. 19-20)

The Board is concerned with the inconsistency in assigning the GNP generation assets as common with the associated transmission lines specifically assigned to Hydro Rural. In principle it would seem logical to assign the transmission plant that connects common generation plant to the interconnected system also as common plant since the generation cannot provide the benefit to the system without those transmission assets. The Board agrees with NLH that the difference in planning criteria for generation and transmission assets is a factor. While the GNP generation assets will delay the need for new capacity on the system no such argument can be made for the transmission assets. The benefit to the interconnected system of the generation arises by virtue of the local generation being able to carry some of the load on the GNP when required thereby reducing the GNP load from other generation sources on the grid. The Board agrees with NLH that these transmission assets can logically be assigned as proposed to Hydro Rural.

The Board accepts NLH's proposed assignment of transmission assets on the GNP to Hydro Rural.

Doyles-Port aux Basques Transmission Assets

NLH proposed continuation of the assignment of the Doyles-Port aux Basques transmission assets as specifically assigned to NP. This proposed treatment is similar to NLH's treatment of the GNP transmission assets.

The transmission assets of the Doyles-Port aux Basques system fall under the assignment guideline involving the connection of a single customer (NP) with remote generation or voltage support equipment to the Island grid. The primary purpose of these transmission assets is to provide service to NP's customers on that radial system. While the generation assets associated with that system are of value to all Island Interconnected customers, NLH submitted that these generation assets are not sufficient in magnitude to justify assignment of the transmission assets as common.

None of the intervenors argued that NLH's proposed assignment of the Doyles-Port aux Basques transmission assets was not appropriate.

EES Consulting recommended the Doyles-Port aux Basques transmission line be assigned common for the same reasons recommended for the assignment of the GNP transmission assets, that being both transmission lines connect generation to the interconnected grid.

NLH's proposed assignment of the Doyles-Port aux Basques transmission line is consistent with the assignment proposed for the GNP transmission assets as discussed above and accepted by the Board. This assignment recognizes that the transmission assets primarily serve NP's customers and hence should be assigned to NP. The benefit of NP's generation assets in the Port aux Basques area to the interconnected system is handled through the use of a generation credit in the COS.

The Board accepts NLH's proposed assignment of transmission assets on the Doyles-Port aux Basques system as specifically assigned to NP.

Burin Peninsula Transmission Assets

Since the Burin Peninsula transmission assets serve both NP and Hydro Rural customers and connect generation assets of NP to the grid, NLH proposed that these transmission assets continue to be assigned as common plant. Prior to the construction of the Paradise River hydroelectric facility in 1989 and the connection of Hydro Rural customers to this transmission system (Monkstown in 1988, Petite Forte in 1993, and South East Bight in 1998), the Burin Peninsula transmission assets were assigned to common plant on the basis of interconnecting significant generation located on the system. While NP is now relocating a 15 MW gas turbine off the Burin Peninsula, the connection of the Paradise River plant and of Hydro Rural customers to the transmission system is, according to NLH, justification for the continued assignment of this plant as common. (IC-291; Exhibit JRH-3, pgs. 21-22)

The IC argued that the Burin Peninsula transmission line TL219 and related generation is directly analogous to the GNP transmission and generation and should be specifically assigned to NP or to a new sub-transmission class for NP and the Hydro Rural customer class. According to the IC TL219 was not constructed, nor is it necessary, to interconnect the Paradise River generating station to the Island Interconnected System; it services primarily NP customers. The IC submitted that TL212 is the only line that physically serves NLH's rural customers and that TL219 and TL212 are not physically interconnected by NLH assets. The IC also suggested that the relative load allocation between the two customer classes, at 99.5% for NP and 0.5% for Hydro Rural should be considered. Assignment of TL219 to common plant increases the costs to the IC by \$230,000. (IC-228; Written Argument, IC, pgs. 25-27; 44)

A COS methodology requires that the specific costs associated with the provision of electrical service be assigned to customers in a fair and equitable manner. Cost assignment is not an exact methodology and often requires the exercise of judgment. In the case of the Burin Peninsula transmission assets the Board recognizes the impact on the IC of the application of the guideline proposed by NLH, which states that transmission assets of substantial benefit to more than one customer should be assigned common. The Board agrees with the IC that the relative load allocation between NP and Hydro Rural (99.5% versus 0.5%) should be considered when allocating costs for these assets. In the Board's view the fact that NLH serves a very small group of customers on the Burin Peninsula is not, in and of itself, sufficient justification to assign these assets as common and thereby shifting more costs to the IC.

NLH has also used as justification in assigning the Burin Peninsula transmission assets as common plant the fact that these assets connect significant generation to the interconnected system. NLH argued that the GNP and Port aux Basques generation was not significant enough to warrant assignment of the associated transmission line to common. The Board accepts that the generation plant on the Burin Peninsula is of larger capacity than that on the GNP and in the Port aux Basques area. While, the Board has no specific guideline against which to measure how much generation would be considered significant enough to justify assignment of costs to common, the Board is not satisfied that the amount of generation capacity is sufficient, in and of itself, to justify assignment of the Burin Peninsula transmission assets to common. The Board also notes that this generation is owned by NP and that the benefit of the generation to the system is handled through the generation credit to NP in the COS.

The Board is persuaded by the IC's argument that the Burin Peninsula transmission assets should be split for the purposes of assigning costs in the COS study. Assignment of some or all of these assets to NP would be consistent with the Board's determination for the GNP and Doyles-Port aux Basques transmission assets and is, in the Board's view, a more equitable allocation of those costs. Based on the evidence it appears that TL212 does provide benefit to all interconnected customers since it connects the Paradise River Generation Station to the grid. In the Board's view TL219 can be considered to be analogous to the Doyles-Port aux Basques transmission assets and that it would be fair and consistent to treat it similarly in the COS study. Therefore, the Board accepts the recommendation of the IC that TL219 should be specifically assigned to NP.

The Board does not accept NLH's proposal to assign all costs associated with the Burin Peninsula transmission assets as common. The Board will direct NLH to separate costs for TL219 and TL212. Costs associated with TL219 will be specifically assigned to NP and costs associated with TL212 will be assigned common.

3. Treatment of NP Generation

NP owns and maintains both thermal and hydraulic generation on the Island Interconnected System. NLH can request NP to run its thermal generation and maximize hydraulic generation when needed to meet system requirements. Compensation for this right to request generation capacity is provided to NP through a generation credit in the COS study. Costs are allocated to NP based on NP's native peak demand less the amount of generation NP has available to NLH on request. The capacity credit for the 2004 COS study is calculated in IC-306 as 125.4 MW, which represents NP's hydraulic and thermal capacity of 145.5 MW less a reserve of 16%.

In its Application NLH did not propose any change in the treatment of NP's generation as a credit in the COS study. The issue of proper recognition of NP's generation was raised by NLH's COS expert in relation to the design of a demand-energy rate. (Pre-filed Evidence, R. D.

Greneman, pg. 17) This issue is considered separately in Part II - Section IX of this Decision and Order.

The IC took issue with NLH's treatment of NP's generation as a credit in the COS. The IC's COS experts supported the recognition of NP's hydraulic generation in meeting system requirements but suggested the credit should only reflect the peak capacity NP provides to the system based on economic dispatch to maximize energy output. Since NP's hydraulic generation is expected to be running at 77.5 MW of output the IC suggested that this figure, and not the 81.6 MW of hydraulic capacity reflective of peak output, should be the amount applied to NP's native peak in allocating capacity related costs in the COS study. (Pre-filed Evidence, C. F. Osler and P. Bowman, pg. 39)

On the issue of the credit for NP's thermal generation the IC's COS experts stated that "*…there does not appear to be any credible basis to provide NP with any generation credit to reflect the thermal plant they have in service.*" (Pre-filed Evidence, C. F. Osler and P. Bowman, pg. 39) They stated that, in contrast to hydraulic generation, NP's thermal generation plays no role in meeting the system energy requirements. According to the IC, NP's thermal production facilities are designed to serve emergency needs in specific service areas and incidentally to provide some peaking capacity to the system. These units represent very high cost energy and are among the last generation dispatched in times of system constraint. The IC argued these thermal units provide no benefit to them and that the IC should not have to pay for peaking capacity owned by NP which is installed primarily for local back-up generation support at the end of radial lines such as on the Burin Peninsula and in Port aux Basques. The IC also submitted that the financial result of the treatment by NLH of NP's thermal generation is that the IC and NLH's rural customers pay for 60% of the cost of NP's peaking generation despite making up only 20% of the island peak. The IC argued that, independent of whatever determination the Board may make on the issue of the demand-energy rate for NP, the credit for NP's thermal generation should be removed entirely and the credit for the hydraulic generation should be reduced to reflect the actual anticipated production as opposed to the potential peak output. (Written Argument, IC, pgs. 32-34)

NP argued that its thermal and hydraulic generation play an important role in NLH's generation planning and system operations and that the peak demands used in NLH's COS should be net of the capacity NP provides to the Island Interconnected System. It was NP's position, supported by its expert, that the Board should approve the continuation of the generation credit to NP consistent with the Board's determination in Order No. P. U. 7(2002-2003). (Brief of Argument, NP, pg. D-15)

EES Consulting dealt with the issue of the treatment of NP's generation in the context of its review of the demand-energy rate for NP. EES Consulting identified a number of options regarding the treatment of NP's generation, including unbundling the NP rate into generation and transmission components and a centralized dispatch system for all system generation. A generation tariff for NP generation payable by NLH was recommended which would eliminate the need for a generation credit. This option would, according to EES Consulting, ensure that financial transactions correspond with the operational flow of energy, thus making it more transparent and robust to changes in cost and load. If this option was not adopted EES

Consulting recommended that NLH be directed to unbundle its COS study such that generation costs are allocated using load data net of the generation credit and transmission costs are allocated using the load data gross of the generation credit. (Pre-filed Evidence, EES Consulting, Sept. 19, 2003, pgs. 33-35)

The CA agreed with the views put forward by the IC and EES Consulting. Since some of the NP generation facilities serve more than one function, including both generation capacity for the entire system and distribution capacity for localized areas, the costs of the generation should be split between those two functions. The CA submitted that the Board continue with the current treatment of NP thermal generation in the COS study but recommended that NLH be directed to commission an independent study of the treatment of NP generation. The study should assess the value of NP generation to the system, and make recommendations on how the generation should be accounted for, both operationally and financially, in the COS study and rate design. (Final Submission, CA, pgs. 31-32)

The Board has considered the issue of the appropriate treatment of NP's generation in previous decisions. In its 1993 report arising from the generic COS hearing the Board recommended that NP's mobile gas turbine at Port aux Basques be included as part of NP's gross generation before adjusting for reserve capacity. The primary consideration for the Board at that time was whether or not NP's mobile gas turbine has an availability commensurate with units NLH counts as firm capability and, as such, could be included by NLH as part of system capacity. (1993 Generic COS Report, pg. 51) In NLH's 2001 general rate hearing the IC argued that NLH's treatment of NP's generation and the IC's non-firm load was inconsistent and unfair. In Order No. P. U. 7(2002-2003) the Board accepted NLH's treatment of the generation credit for NP.

None of the parties suggested that NP should not be given credit for its hydraulic generation. The IC argued that the credit for the hydraulic production should be reduced from 81.6 MW to 77.5 MW to reflect the actual anticipated production as opposed to the potential peak output. The Board notes that the methodology used by NLH in IC-306 to calculate NP's generation credit is the same as used by NLH in its 2001 general rate hearing and approved by the Board. The Board does not agree that the credit for hydraulic production should be reduced as proposed by the IC. NP's native load coincident peak is calculated by adding NP's coincident peak as forecast by NLH and NP's forecast hydraulic generation. The hydraulic capacity credit of 81.6 MW is calculated using the available hydraulic capacity of 94.6 MW less 16% reserve capacity. The forecast hydraulic output of 77.5 MW is a forecast production number for the purposes of calculating NP's native load for the 2004 test year, and depends on forecast hydraulic and operating conditions. The calculation of the net capacity credit is, in the Board's opinion, a proper recognition of the hydraulic capacity available to NLH for the purposes of applying a generation credit to NP's coincident peak in the COS study.

The Board is not persuaded that NP's thermal generation should be treated any differently than NP's hydraulic generation for the purposes of calculating the capacity credit. Both NP's thermal and hydraulic generation are available to NLH for generation planning and system operations and, as such, NP should be given a credit for this capacity. While NP's thermal generation may not be used to the same extent or for the same purpose as NP's hydraulic generation, primarily because of its higher cost, the thermal generation still comprises available capacity for NLH in terms of the island system capability. Therefore, the Board agrees that NLH should provide a credit to NP for its thermal generation.

The Board notes however the concern raised by the IC regarding the apparent inconsistencies that arise when the credit is applied in the COS study and the resulting costs allocated to the IC. Table 6.4 on page 30 of the IC's COS expert's pre-filed evidence outlines the costs to the IC of various peaking capacities from the COS study. This Table shows costs to the IC of \$16.23/kW for 45.5 MW of NP's generation, versus \$2.19/kW for 128 MW from NLH's gas turbines. The IC raised this issue during cross-examination of Mr. Greneman:

> Q. (Mr. Hutchings): Okay. And again, going back to the table, the top entry there refers to Hydro's gas turbines and the provision of 129 kilowatts of peaking capacity – 128,000 kilowatts of peaking capacity at a cost to the Industrial Customers of \$280,613. You agree that that's the way that the cost of service assigns those costs?
> A. (Mr. Greneman): That's my understanding. I'll agree to that.
> Q. Okay. Now sir, if Hydro's gas turbines, which I would suggest to you serve essentially the same function on the system as Newfoundland Power's gas turbines, are charged to the Industrial Customers for the benefit of 128,000 kilowatts for \$280,000, what is fair about the Industrial Customers paying \$738,000 for 45,500 kilowatts?
> A. I noted in Mr. Osler's and Mr. Bowman's testimony yesterday that the same point was being made and perhaps it needs some attention or some look at.
> Q. Would you agree with me that there is an unfairness present on the face of this?
> A. I'm not going to use the word "unfairness" but there seems to be some sort of inequality.
> Q. Would you agree that this is not a result that would be consistent with the proper principles of cost allocation to be applied in the public utility setting?
> A. At this moment, I wouldn't go so far as to say that. I would simply say it merits review.
> Q. Okay. And are you telling us that you have not reviewed the issue?
> A. I note that there might be an anomaly but I'm not 100 percent sure what the remedy is.
> (Transcript, Nov. 14, 2003, pgs. 217/4-2; 218/l1-14)

Mr. D. Bowman, the CA's COS expert witness stated: *"I do see some discrepancies in the whole issue of the generation credit. I certainly am sympathetic to the evidence put forward by the Industrial Customers."* (Transcript, Nov. 17, 2003, pg. 109/16-19) Mr. Brockman agreed that the COS result is an anomaly but suggested that it would not be proper to deal with only this aspect of the COS methodology in isolation. (Transcript, Nov. 18, 2003, pg. 106/14-21)

Although the treatment of NP's thermal generation credit seems to result in an anomaly when the cost per kW charged to the IC for this credit is compared to that charged for NLH's gas turbines, which essentially serve the same purpose, the answer appears to be found in Table 6.4 on page 30 of Mr. Osler and Mr. Bowman's pre-filed evidence. The Board understands from this Table that NP makes up 80.6% of the system peak and hence bears 80.6% of the cost. The IC bear 12.64% of the cost, and Rural Customers 6.76%. Any credit, therefore, would be proportionally allocated in the same manner. Since there are only three customers sharing these costs (NP, IC and Rural Customers), any credit to NP for the use of its plant will be a cost to the other customers. Under the current COS methodology and recognizing the contribution of NP's thermal plant to the Interconnected system, the Board finds that the allocation of the NP thermal generation credit is appropriately determined.

In light of the concerns and issues raised in this hearing the Board does agree, however, with the CA's recommendation that an independent study of the treatment of NP's generation is warranted. The Board will direct that NLH undertake such a review, as proposed by the CA, to be filed with its next general rate application.

The Board accepts NLH's treatment of NP's hydraulic and thermal generation in the COS study.

The Board will direct NLH to commission an independent study, to be filed with its next general rate application, of the treatment of NP's generation. This study should assess the value of NP's generation to the system and make recommendations on how the generation should be accounted for, both operationally and financially, in the COS study and rate design. NLH will be permitted to recover its reasonable costs associated with this study and may accumulate these costs in a deferral account to be dealt with at its next general rate application.

4. NP Demand Forecasts

The IC raised the issue of the accuracy of NP's forecasts of peak demand and energy and the impact of these forecasts on the costs that are allocated to the IC in the COS study. The forecast COS study for 2002 was approved as a result of NLH's 2001 general rate hearing. The IC contended that NP's actual payments to NLH were approximately $5,000,000 lower than the amount that should have been allocated by rates (including the rural deficit), while the IC paid more than $5,000,000 in excess of its measured costs in 2002 (including RSP adjustments). (Pre-filed Evidence, C. F. Osler and P. Bowman, pg. 39/12-19) According to the IC the variance in NP's actual load factor compared to its 2002 forecast is one of the contributing factors for this difference.

The IC's experts recommended that NP's load forecasts need to be reviewed to assess the extent to which NP's peak demands as forecast result in a reasonable allocation of demand costs. (Pre-filed Evidence, C. F. Osler and P. Bowman, pg. 3/30-31) In final argument (pg. 31) the IC submitted that NP's peak demand forecast for COS allocations be increased by 16.3 MW to make it consistent with actual five year average load factors.

NP argued there is no pattern in the annual variances between NP's forecast and actual demand. NP acknowledged the variation identified by the IC for the 2002 test year. As a result of this variance NP and NLH agreed on a revised forecast methodology to reflect a longer historic period to estimate an expected peak. NP now bases its demand forecast on a 15-year average load factor. NP submitted that its demand forecast for the 2004 test year is reasonable. (Brief of Argument, NP, pgs. D-15 to D-17)

NLH confirmed its acceptance of this methodology during cross-examination:

> A. (Mr. Haynes)…they have made some changes to that methodology in the last little while which we fully agree with and the actual load factor for Newfoundland Power's native peak is basically, I understand now, a 15-year average which is 49 ½ percent and there was some discussion on that last time through. And so, Newfoundland and Labrador Hydro reviewed that and we fully agreed with using the 15, the long term load

> factor because it looks after some of these, you know, some of the other—the cold winters and the mild winters, it's an average load factor and I guess at one point in time, they were using a shorter period and now it's a longer period which we fully endorse and agree with.
> (Transcript, Nov 12, 2003, pgs. 190/25; 191/1-15)

The Board agrees with the IC's recommendation that the Board review the test year load forecasts in determining revenue requirement. This is necessary to ensure that the allocation of costs from the COS study is fair and that customers only pay those costs attributable to their demands on the system. The forecasts for the 2002 test year were reviewed and accepted by the Board in Order No. P. U. 7(2002-2003). The very nature of forecasts is such that the results will most likely be different than expected, because of variable conditions such as end-use customer loads and weather conditions. While the Board has no basis to dispute the IC's contention that the actual 2002 COS results are significantly different than forecast the Board sees no merit in addressing this specific issue further. Rates are based on forecast costs (as required by the *EPCA*) and the Board does not engage in retroactive rate setting or adjustments.

The Board reviews the forecasts used in determining the 2004 test year revenue requirement to ensure that the forecasts are based on reasonable expectations and take into account any anticipated changes in circumstances. The Board has not been presented with any evidence that NP's demand and energy forecasts are inaccurate or biased, either from a historical basis or for the 2004 test year forecast. A review of IC-155, which provides forecast and actual system sales and load for NLH's customers for the period 1994-2001, shows variations in both demand and energy forecasts for NP and the IC. In the Board's opinion NLH and NP have acted appropriately in addressing the variance in the 2002 demand by using a longer historic period for forecasting the expected peak and hence determining the load factor. The Board will make no adjustment to NP's demand forecast for the 2004 test year.

The Board accepts the demand and energy forecasts for NP as proposed by NLH for use in the 2004 test year COS study.

VII. LABRADOR INTERCONNECTED SYSTEM

1. Introduction

In Order No. P. U. 7(2002-2003) the Board approved NLH's proposal to simplify rate classes and structures for the Labrador Interconnected System and also to implement uniform interconnected rates for customers in Happy Valley-Goose Bay, Labrador City and Wabush. As a result the 24 different rate classes were consolidated into six (6) rate classes which aligned with those in place on the Island Interconnected System. The Board also approved NLH's proposal to equalize rates for customers in Labrador City and Wabush. The Board ordered NLH to file a five year plan for implementation of a uniform rate structure for the Labrador Interconnected System as part of its next rate application and acknowledged NLH's efforts to keep the increases to a level that would not cause rate shock as it moved toward uniform rates.

NLH filed with its Application a proposal to implement uniform rates in the Labrador Interconnected System as directed by the Board in Order No. P. U. 7(2002-2003).

Following the filing of this Application Government directed the Board to hold a hearing into the appropriate rate calculation methodology for the Labrador Interconnected System upon receipt of a complaint of discriminatory rates. The Towns of Labrador City and Wabush subsequently filed a complaint. (Appendix E) The Board heard evidence and argument relating to this complaint as part of this proceeding in Labrador City, Happy Valley-Goose Bay and in St. John's.

Before examining the positions of the parties respecting NLH's rate proposals for customers on the Labrador Interconnected System it is helpful to summarize the development of the electrical system in the region and to review the history of the Board's recommendations and decisions with respect to rates and Cost of Service (COS) methodology for the Labrador Interconnected System.

2. Development of the Electrical System in Labrador West and Happy Valley-Goose Bay

The development of the electrical system in the Happy Valley-Goose Bay area and Labrador West was influenced by the history and growth of the townsites of Labrador City and Wabush. NLH provided a summary of the development of the respective systems in opening comments during the hearing in Labrador City and Happy Valley-Goose Bay. (Transcript, Nov. 26, 2003, pgs. 18-25; Nov. 27, 2003, pgs. 14-18)

<u>Labrador City</u>

From 1965 to 1991 the electrical distribution system for the Town of Labrador City and adjacent sites was provided by the Iron Ore Company of Canada (IOCC) under the terms of an agreement dated December 14, 1965 between IOCC and the Board. This agreement included a schedule of rates and a schedule of regulations and conditions of service. IOCC and NLH entered into an agreement dated December 3, 1991 whereby, subject to the approval of the Board, IOCC agreed to transfer to NLH as of May 1, 1992 the electrical distribution system serving the Labrador City service area. NLH agreed to operate, maintain and upgrade the system to standards provided for in the agreement. The Board approved the transfer in Order No. P. U. 4(1992). The rates, regulations and conditions of service as provided by IOCC under the previous agreement were continued by NLH. These rates remained at the 1992 level until 2002 when new rates were set for all of NLH's customers as a result of NLH's 2001 general rate application.

Wabush

Wabush Mines initially provided electrical service to the residents and businesses in the Town of Wabush under the terms of an agreement between Wabush Mines and the Board dated December 1965. This agreement exempted Wabush Mines as a public utility but obligated the company to provide safe service. In 1982 the Town of Wabush filed a complaint regarding the provision of adequate electrical service with the Board. Following an investigation the Board wrote to Wabush Mines and ordered it to upgrade the system to a safe and reliable standard. Following discussions between the Provincial Government, Wabush Mines and NLH, in 1985 it was agreed that NLH would assume responsibility for the electrical distribution system in the town. Wabush Mines agreed to pay to the Power Distribution District (PDD)[1] a sum of money equivalent to the lesser of $3,000,000 or the amount of funds required to repair, restore and upgrade the distribution system. This money would be paid in annual instalments of $500,000. The PDD agreed to take responsibility for the restoration of the system.

The PDD filed rate referrals for the Wabush Service Area with the Board in 1985 (to confirm interim rates for 1985 and to set rates for 1986, 1987 and 1988) and in 1987 (for rates for 1988, 1989 and 1990). The Board's findings and recommendations following the 1987 referral resulted in appeals to the Courts by both the Towns of Wabush and the PDD. The LGIC approved the rates for 1988 but deferred consideration of recommended rates for 1989 and 1990 pending disposition of the appeals. The Courts remitted the matter back to the Board following which rates for 1989 were recommended and approved. Rates in Wabush remained at the 1989 level until 2002 when new rates were set for all of NLH's customers as a result of NLH's 2001 general rate application.

Happy Valley-Goose Bay

Prior to 1976 electricity was supplied to the Goose Bay airport area by the Federal Department of Public Works. In December 1976 this distribution responsibility was transferred to the PDD. The issue of the rates to be charged by the PDD in the Happy Valley-Goose Bay area was considered at a 1978 public hearing on the rates to be charged by the PDD. In its 1979 report to Government the Board recommended, among other things, that the specific rates for Labrador Interconnected customers should be those charged by NP on the Island Interconnected

[1] The Power Distribution District of Newfoundland and Labrador (PDD) was established 1971 to manage electrification to rural areas of the Province. NLH assumed responsibility for the PDD assets and operations in 1989 and acquired the direct responsibility to provide service to those customers.

System, including the application of the fuel adjustment charge. The Board also recommended this rate be charged until such time as the sales volume had increased to provide revenue sufficient to equal the cost of service. In 1981 the rates in Happy Valley-Goose Bay area were set by Board Order to be the same as the rates charged by NP on the Island Interconnected System, excluding the fuel adjustment charge. Rates remained at the 1981 level until 2002 when new rates were set for all of NLH's customers following NLH's 2001 general rate hearing.

Present System

Approximately 8,900 customers are served on the Labrador Interconnected System. Virtually all power and energy made available by NLH for the Labrador Interconnected System is purchased from Churchill Falls (Labrador) Corporation Limited [CF(L)Co.] NLH has a total of 300 MW and 2,362 GWh available annually, with any surplus to NLH's needs currently sold to Hydro-Quebec. (Pre-filed Evidence, J. R. Haynes, pg. 7)

NLH owns 269 km of 138 kV transmission line and the associated terminal stations interconnecting Happy Valley-Goose Bay to Churchill Falls. NLH also owns 44 km of 46 kV sub-transmission lines in Labrador West, of which 25 km provides an emergency interconnection between Labrador West and Fermont, Quebec. Customers in Labrador West are serviced under an arrangement with TwinCo, the owner of the transmission facilities, for wheeling electrical energy from Churchill Falls.

NLH also owns and maintains 336 km of low voltage distribution lines and 9 substations in Wabush, Labrador City, Happy Valley-Goose Bay, Northwest River, Sheshatshiu, Mud Lake and limited distribution facilities in Churchill Falls. There is also standby generation consisting of a gas turbine and a diesel plant in Happy Valley-Goose Bay, with a total capacity of 38.3 MW, used primarily for back-up and limited peaking capacity. NLH's Energy Control Centre remotely operates the gas turbine.

3. History of Cost of Service for the Labrador Interconnected System

In its 1979 report the Board recommended that, in order to deal with the question of rates, the PDD be separated into three separate areas: Diesel, Island Interconnect and Labrador Interconnect. The Board also recommended that "*the Labrador Interconnect area should be considered as a distinct region with its own cost of service and rates both at present and when the Labrador and Island portion of the province are interconnected because the area is completely separate as is its source of supply of power.*"

In 1991 the *EPCA, R.S.N., 1990* was amended to remove the exemption given to Labrador Interconnected customers with respect to their share of the funding of the rural deficit. In late 1991 NLH referred an application to the Board for rate increases and classification changes for the Labrador Interconnected customers. Subsequent to the filing, the referral was amended to delete the increases requested for the Labrador Interconnected System. Since NLH did not file a rate referral or application on Labrador Interconnected rates until 2001, these customers had not contributed to the funding of the rural deficit (as required by the *EPCA*) during the period 1991 to 2001.

The issue of the COS methodology to be used by NLH in setting rates for all customers was reviewed by the Board at a generic COS hearing beginning in 1992. At this hearing the question of the appropriate methodology to be used for the Labrador Interconnected System was considered. In its 1993 report following from that hearing the Board stated at pg. 10:

> *"The Board agrees with Hydro's view that questions of cost of service methodology should be settled as result of the present hearing. The Towns have not submitted any evidence or arguments to show that costs in Labrador Interconnected System are not appropriately allocated by means of a single cost of service study, or that the rate class structure adopted by Hydro for that system is inappropriate. The Board is not aware of any instance where more than one embedded cost of service study has been deemed necessary for a single interconnected system and moreover considers that all customers served within the Labrador Interconnected System share common costs of generation, transmission and a variety of overheads. It therefore concludes that a single cost of service study is appropriate for that system."*

The Board recommended the structure adopted by NLH for COS purposes comprising one study for the Island Interconnected System, one for the Labrador Interconnected System and one for all Isolated Rural Systems be approved. The Board also recommended that the rural deficit be allocated to consumers of electricity, with the exception of rural customers, on the basis of units of consumption of demand, energy and number of customers. The Board's report, dated February 1993, was submitted to Government and subsequently approved in 1998.

The issue of the rates to be charged by NLH to its Rural customers was again considered by the Board in 1995 as part of the rural rate inquiry. In its 1996 report the Board recommended that there be a separate COS study for the Labrador Interconnected System, including Labrador West and the Happy Valley-Goose Bay area.

During NLH's 2001 general rate hearing the issue of the appropriate methodology for setting rates was again raised by the Towns of Labrador City and Wabush. In Order No. P. U. 7(2002-2003) the Board found that the Labrador Interconnected System should be treated as one system for the purposes of setting rates.

4. Application Proposals for the Labrador Interconnected System

In this Application NLH is proposing a five year plan to implement uniform rates for Labrador Interconnected customers using the following cost recovery targets:

Domestic	95%
General Service	105%-115%
Street Lighting	100%

NLH's proposal also incorporates the Board's direction in Order No. P. U. 7(2002-2003) to phase in the application of the revenue credit for secondary energy sales to CFB Goose Bay to the rural deficit. This revenue credit was previously applied to the COS for the Labrador Interconnected System. The Mediation Report recommended:

> *"dd. Hydro will adjust the Rural Rate Alteration Component of the RSP based on its projection of the 5-year phase-in of Labrador rates and the revenue credit available from secondary energy sales to CFB Goose Bay."*

NLH's proposal for the phase-in of rates on the Labrador Interconnected System is set out below:

Target Rate Recoveries Labrador Interconnected System							
	Current Rate	Target Rate	Target Rate Level[1]				
Customer	Recovery	Recovery	2004	2005	2006	2007	2008
Happy Valley/Goose Bay							
Domestic	100%	100%					
General Service 2.1	66%	100%	76%	86%	100%		
General Service 2.2	120%	100%	120%	113%	100%		
General Service 2.3	134%	100%	134%	121%	100%		
General Service 2.4	133%	100%	133%	121%	100%		
Street and Area Lighting	95%	100%	100%	100%			
Labrador West							
Domestic	41%	100%	53%	62%	72%	85%	100%
General Service 2.1	51%	100%	66%	73%	80%	89%	100%
General Service 2.2	74%	100%	89%	100%			
General Service 2.3	77%	100%	92%	100%			
General Service 2.4	82%	100%	98%	100%			
Street and Area Lighting	38%	100%	60%	70%	80%	90%	100%

[1] The target rate level is based on each rate class' appropriate rate being 100%. The appropriate rate is calculated based on the cost recovery targets plus the rate class' portion of the rural deficit.

(Revised Evidence, S. D. Banfield, Table 2, Oct. 31, 2003, pg. 12)

The proposed phase-in of uniform rates outlined above limits average rate increases for each class to a maximum of 20% in years 2005 to 2008. However, the revenue requirement necessitates a 28% increase in 2004 for Labrador West. (Revised Evidence, S. D. Banfield, Oct. 31, 2003, pg. 12/12-15) NLH's existing and proposed rates for domestic and general service customers in Happy Valley-Goose Bay and Labrador West are outlined on the following page.

Comparison of Proposed Rates Schedules 2004-2008
Labrador Interconnected System

Happy Valley-Goose Bay

	Rate Class	2003[1]	2004[2] Aug 12	2004[3]	2005	2006	2007	2008
Basic Charge $/mo	1.1	7.00	7.00	7.00	7.00	7.00	7.00	8.00
kWh Charge ¢/kWh		3.25	3.25	3.25	3.25	3.25	3.25	3.274
Basic Charge $/mo	2.1	9.10	9.10	9.10	9.10	10.10		
kWh Charge ¢/kWh		3.16	4.032	4.290	4.742	5.086		
Demand Charge $/kW/mo	2.2	2.00	2.00	2.00	2.00	2.00		
kWh Charge ¢/kWh		3.00	3.00	3.00	2.787	2.398		
Demand Charge $/kVa/mo	2.3	1.85	1.85	1.85	1.85	1.85		
kWh Charge ¢/kWh		2.95	2.95	2.95	2.601	2.116		
Demand Charge $/kVa/mo	2.4	1.70	1.70	1.70	1.70	1.70		
kWh Charge ¢/kWh		2.50	2.50	2.50	2.260	1.808		
Demand Charge $/kW/mo	3.1*	2.00	2.00	2.00				
kWh Charge ¢/kWh		2.50	2.50	2.50				

* Effective January 2005, Rate 3.1 will be eliminated and customers will become part of Rate 2.2 and 2.3

Labrador West

	Rate Class	2003[1]	2004[2] Aug 12	2004[3]	2005	2006	2007	2008
Basic Charge $/mo	1.1	3.75	4.45	4.85	5.50	6.25	7.15	8.00
kWh Charge ¢/kWh		1.35	1.601	1.723	2.039	2.371	2.804	3.274
Basic Charge $/mo	2.1	9.10	9.10	9.10	9.10	9.10	9.55	10.10
kWh Charge ¢/kWh		2.20	2.832	3.072	3.520	3.945	4.450	5.086
Demand Charge $/kW/mo	2.2	2.00	2.00	2.00	2.00			
kWh Charge ¢/kWh		1.60	2.056	2.241	2.398			
Demand Charge $/kVa/mo	2.3	1.85	1.85	1.85	1.85			
kWh Charge ¢/kWh		1.50	1.882	2.069	2.116			
Demand Charge $/kVa/mo	2.4	1.70	1.70	1.70	1.70			
kWh Charge ¢/kWh		1.70	1.731	1.779	1.808			

Note: Blank cells indicate that there are no further change in rates.
[1] Current rates.
[2] Proposed 2004 rates that had been included in the Aug. 12, 2003 filing with the Board. (Revised Evidence, S. D. Banfield, Schedule V, Aug. 12, 2003, pg. 1)
[3] Revised Evidence, S. D. Banfield, Schedule V, Oct. 31, 2003, pg. 1.

NLH requested that the Board approve that the rate schedules filed for customers on the Labrador Interconnected System automatically come into effect January 1 of each year with the provision that adjustments could be made should a general rate application be filed in the intervening period.

5. Complaint of the Towns of Labrador City and Wabush

The Towns of Labrador City and Wabush argued that NLH's proposed rates for the Labrador Interconnected System discriminate against electrical consumers in Labrador West since NLH's proposals fail to align rates with COS and fail to recover costs from the customers that cause them. (Brief of Argument, Towns of Labrador City and Wabush, pg. 34; para. 98) The Towns submitted that NLH's proposal for uniform rates is based on the fallacy that the two separate systems serving Labrador East and Labrador West should be treated as a single interconnected system. According to the Towns, these systems are not interconnected and have always existed distinctively with no operational relationship between them. The Towns submitted that the transmission line from Churchill Falls to Happy Valley-Goose Bay and the back up generation capacity in Happy Valley-Goose Bay is for service to Labrador East and has no relevance to Labrador West. Customers in Labrador West therefore should not have to subsidize the higher costs associated with electrical service to Labrador East.

Evidence of Mr. Mark Drazen, the expert witness for the Towns of Labrador City and Wabush, quantified the difference in costs for providing electrical service to Labrador West and Labrador East. (Revised Evidence, M. Drazen, Oct. 3, 2003, pg. 2) Mr. Drazen stated that, although both areas receive power from Churchill Falls, the nature and costs of the other facilities serving the two communities are different. According to Mr. Drazen there are cost differences in all three major components of cost (generation, transmission and distribution) resulting from differences in the type of facilities, the ownership of those facilities, and the costs incurred by NLH. Mr. Drazen also stated that the fact that the transmission lines to Labrador West and Labrador East are connected to a common generating source does not mean it is appropriate to allocate the costs as if they were a common system. In Mr. Drazen's opinion NLH's proposal to equalize the costs of the two areas amounts to a policy decision to ignore the material cost differences between the two. As NLH already produces separate COS studies for five different sub-systems based on the different facilities and cost of service among the five areas, Mr. Drazen submitted that there is no inherent policy that requires the rates in Labrador East and Labrador West to be equalized.

The Mayor of the Town of Labrador City, Mr. Graham Letto, and the Mayor of Wabush, Mr. Jim Farrell each made a presentation to the Board in Labrador City. Both Mr. Letto and Mr. Farrell reiterated the positions of the Towns that NLH's proposal to adopt a system of uniform rates for customers in Labrador West and Labrador East amounts to discrimination against consumers in Labrador West. Mr. Letto stated:

> (Mayor Letto) Given the different characteristics of the systems of Labrador West and that in Happy Valley-Goose Bay, and also given that the contributions to cost made by the mining companies in this area, the cost of distributing electrical power to consumers in Labrador West is lower than that required to distribute power to consumers in Happy Valley-Goose Bay. By merging the two systems and posing a system of uniform rates on a so called, Labrador Interconnected grid or a system, Hydro has adopted an arbitrary policy requiring consumers in Labrador West to do nothing more than to subsidize those in Happy Valley-Goose Bay. This arbitrary policy is contrary to principle and amounts to discrimination against consumers in Labrador West.
>
> (Transcript, Nov. 26, 2003, pgs. 158/22-25; 159/1-14)

Both Mayor Letto and Mayor Farrell spoke of the effect of the proposed rate increase on IOCC and Wabush Mines at a time when, due to poor prices and markets, the companies cannot afford any additional burdens. The issue of the collection of the rural deficit through electrical rates was also raised by both Mayors. While the Towns of Labrador City and Wabush stated they don't object in principle to the subsidization of rural electricity rates, such a subsidy is in effect a social tax. As a tax the Mayors stated it ought to be collected through the legislature rather than imposed on certain electrical consumers in the Province. Mayor Farrell summarized the position of the Town of Wabush by stating:

> (Mayor Farrell) Consumers in Labrador West pay electricity rates based on the cost to service Labrador West, together with contribution to the rural deficit. Labrador West should not be required to subsidize Happy Valley-Goose Bay consumers. Hydro should not be placing Labrador West citizens in a position where Labrador West consumers are forced into a direct conflict with those in Happy Valley-Goose Bay.
> (Transcript, Nov. 26, 2003, pg. 177/2-10)

The position of the Towns of Labrador City and Wabush was summarized in final argument (pgs. 22-23):

> *"In conclusion, NLH's proposed policy to institute a single rate structure throughout the so-called Labrador Interconnected System would ignore material cost differences between Labrador East and Labrador West. There is no general policy of rate equalization on the NLH system. Indeed NLH proposes five sets of rates reflecting cost differences among five different sub-systems: Island Interconnected, Island Isolated, Labrador Isolated, L'Anse au Loup and Labrador Interconnected. Systemization is based on the different facilities and costs of service among those five areas. There is no inherent policy that requires the Labrador Interconnected East and the Labrador Interconnected West rates to be equalized. The reasons put forth by NLH's expert Mr. Greneman and the PUB's expert Ms. Tabone, amount to saying "it's a policy decision" but, with respect, do not provide any basis for that policy.*
>
> *The proposed policy of a single rate in Labrador East and Labrador West would discriminate against customers in Labrador West and is directly contrary to the principle that a utility ought to recover costs from the customers that cause such costs to be incurred."*

During the hearing in Labrador City Mr. Dave Porter, Vice-President of Human Resources for IOCC, and Mr. John McGrath, Director of Human Resources for Wabush Mines, made a joint presentation to the Board. Mr. Porter provided a history of the development of the electrical system in Labrador City and Wabush, including the contributions of both IOCC and Wabush. According to Mr. Porter there should be a significant difference in the COS between Labrador West and Labrador East because IOCC and Wabush Mines paid for the electrical infrastructure in Western Labrador. The need to attract and retain a highly skilled workforce to Labrador West was cited as one of the reasons IOCC originally paid for the town's electrical infrastructure. A common rate for Labrador East and West will dilute the effect in Labrador West of the mining companies past contributions to infrastructure and the present subsidy of wheeling at no cost. The companies support NLH raising electrical rates in Labrador West if required to compensate for an increased cost to service Labrador West but do not support raising Labrador West rates and lowering Labrador East rates in an effort to create a common rate policy. The witnesses argued this would effectively result in the companies paying twice for the infrastructure. The impact of the proposed increase in rates on the companies, its employees and the area was stressed. Mr. Porter stated that the uniform rate policy will result in more than four million dollars in additional costs annually for electrical consumers in Labrador West. The mining companies will ultimately have to bear a substantial portion of these increases in costs.

The Board also heard a number of presentations from representatives of unions, Chambers of Commerce, business persons and private citizens, all of whom spoke about the challenges and high costs associated with living in Labrador West and the impact of the rate increases proposed by NLH on businesses and residents in Labrador West.

Mr. Dennis Peck, Director of Economic Development for the Town of Happy Valley-Goose Bay, made a presentation before the Board in Happy Valley-Goose Bay. The Town supported NLH's proposal for uniform rates in the Labrador Interconnected System, and stated that there has always been a concern that there was a fundamental unfairness to the existing rate structure, even though they receive the same product delivered from essentially the same infrastructure and generated by the same source. Mr. Peck stated:

> (Mr. Peck) It is simply not fair that we continue to be asked to fund the lion's share of the subsidy, pay significantly higher rates, and as a direct result of the higher cost, pay a greater share of the HST tax within the Labrador Interconnected system. The longer this imbalance continues, the longer the injustice is allowed to endure.
>
> (Transcript, Nov. 27, 2003, pgs. 44/25; 45/2-8)

His response to the position of the Towns of Labrador City and Wabush that the electrical system in Labrador East and Labrador West should be considered as separate systems was as follows:

> (Mr. Peck) At the very minimum we feel that Mr. Drazen stretched the concept of a system to the very thinnest of definitions to make his case. We consider the concept of looking at the different sides of a generating facility and to suggest that each side of a power plant, and each division of each side is a different system, is to stretch the definition beyond the point of reality. I note that in the extra evidence that was submitted there was a sketch provided by Newfoundland and Labrador Hydro about the layout at Churchill Falls, and I had difficulty whether you could flip it left or right to see the differences between it. If we were to take this logic to the map of the total system on the Island of Newfoundland, and I've provided a copy, where will implementation of this request actually take us, how fine of a division will result if the rationale is followed to its final conclusion. I suggest that this argument is neither appropriate nor in keeping with the intent of Section 73(1) of the Public Utilities Act which states that "all tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, and the Board may by regulation declare what shall constitute substantially similar circumstances and conditions.
>
> (Transcript, Nov. 27, 2003, pgs. 36/11-25; 37/2-18)

Mr. Peck took issue with the position of the Towns of Labrador City and Wabush regarding the value to Labrador West of the back-up generation in Happy Valley-Goose Bay. Mr. Peck also commented with respect to the transmission of power at no cost over the TwinCo line, that *"there is no such thing as a free ride nor a service provided at no cost"* and that *"arguments suggesting differences within the Labrador Interconnected System may in the coming years come back to haunt those who raise it."* (Transcript, Nov. 27, 2003, pgs. 37/19-25; 38/1-25)

NLH filed supplementary evidence specifically relating to the Labrador Interconnected System outlining the impacts of the proposed rate implementation plan on customers. NLH's COS expert Mr. Greneman supported the development of rates for the Happy Valley-Goose Bay area and Labrador West based on a single Labrador Interconnected System. Mr. Greneman submitted that costing and pricing the Labrador Interconnected System as a single combined system is consistent with existing practices and policies and strikes a fair and reasonable balance among a number of relevant factors. Mr. Greneman stated that, while costs are a factor, there are other equally relevant factors that should be considered. These include price signals, value of service, opportunity cost and public policy. Mr. Greneman outlined the basic goal of COS is to determine the relative cost differences between customer classes and it is important to maintain a degree of consistency between the same customer classes within regions. This is evidenced in the combining of isolated diesel rates for costing and rate purposes with pricing in part reflective of NP's rates and, as well, by the fact that NLH's Island Interconnected customers are charged NP's rates. According to Mr. Greneman, having separate domestic and general service rates for Labrador East and Labrador West would potentially result in significant price differences between otherwise similar circumstances. (Supplementary Evidence, R. D. Greneman, Oct. 31, 2003)

In final argument NLH reiterated that, while there may be differences in certain elements of costs such as transmission and distribution between the two areas, this situation is not unlike the isolated diesel areas. All the diesel systems are included within one COS study and treated as one for the purposes of designing rates. Furthermore, this is not unlike what occurs between different communities served on the Island Interconnected System. NLH argued that cost differences alone are not sufficient to justify separation of systems for rate setting purposes. NLH submitted there is sufficient evidence before the Board to support the Labrador Interconnected System being treated as one system for the purposes of setting rates. NLH argued the Board should approve NLH's proposed rate design and implementation plan for Labrador Interconnected customers for the period 2004-2008. (Final Argument, NLH, pgs. 75/17-29; 76/1-16)

EES Consulting submitted that the communities in Labrador receiving supply from Churchill Falls constitute an interconnected system and should not be separated into multiple systems for COS analyses. According to EES Consulting the Labrador system is more like the Island Interconnected System with shared generation facilities and some shared transmission facilities. The fact that actual costs vary by location does not justify different rates. *"Postage stamp"* rates, where a single rate is set for the full interconnected system, are standard practice for distribution utilities to ensure fair, equitable and stable rates. EES Consulting also stated that the original purchase price does not denote the value of a system and should not enter into the COS analysis. EES Consulting recommended that there continue to be a single COS for the Labrador Interconnected System and that rates be the same within the system, regardless of the location of the customer. (Pre-filed Evidence, EES Consulting, Sept. 19, 2003, pgs. 16-17)

In final argument (pg. 44) the CA stated that his mandate is to represent all of the consumers of the Province. In this particular case the CA noted there are competing interests. The CA submitted that the Board should carefully examine all the evidence so that the Board's decision ensures that there is no undue subsidization between ratepayers in Labrador West and Labrador East.

The IC and NP did not take a position or make submissions on this issue.

In making its decision with respect to this issue the Board must be guided in the first instance by its legislative mandate under the *EPCA* and the *Act.* Section 3 of the *EPCA* sets out the power policy of the province, including the requirement in Section 3(a)(i) that rates for the supply of power within the province should be reasonable and not unjustly discriminatory. Section 4 of the *EPCA* requires the Board to implement the power policy declared in Section 3 and to apply tests which are consistent with generally accepted sound public utility practice. The Board has outlined its guiding regulatory principles in Part I - Section IV of this Decision and Order.

Differences in rates will exist due to the nature of rate making and the methodologies associated with using generally accepted sound public utility practice. In the rate making process it is often not practical to develop a multitude of rates to accurately reflect the individual circumstances of different electrical consumers. For example a consumer who lives near a generation source may argue that she/he requires less transmission, and hence should pay lower rates than another consumer who lives further away. Since it would be impractical to design individual rates for each consumer, consumers are usually grouped into rate classes according to the type of service they use (e.g. residential, general service, industrial) with one rate for the entire class, regardless of geography or individual circumstance.

The Towns of Labrador City and Wabush argue that Labrador West and Labrador East should be considered separately for rate setting purposes because of the significant cost differences between the two systems and also because of the historical factors contributing to the development of the Labrador West system. The Board will deal with each of these issues separately.

The Board does not accept the argument of the Towns of Labrador City and Wabush that the historical development of the electrical system in Labrador West is a factor that should be considered when determining whether to have uniform rates in Labrador West and Labrador East. While the evolution of the electrical distribution system in Labrador West certainly plays a role in the nature and costs of the system in place today, the Board is only concerned with setting rates on a prospective basis as required by legislation. The contributions of IOCC and Wabush Mines toward the costs of the existing system in Labrador West were undertaken when the companies owned and operated the systems and were a consideration when NLH negotiated the take over of the systems. Any claim to an expected or ongoing benefit in terms of continued low rates after the asset transfer to NLH, as suggested by the Towns, is not supported by the transfer agreements.

In the Board's view the development of the electrical distribution system in Labrador West is similar to the development of the existing Island Interconnected System, where several smaller systems owned by various operators in different geographic locations were amalgamated over time into a single system with ownership and operating responsibilities resting with a single entity. Indeed this is the nature of the development of many of the existing electrical systems in Canada where technical improvements and economies of scale made this a reasonable and practical course of action.

The Board's conclusions with respect to the issue of uniform rates for the Island Interconnected System in 1968, while not binding, are of interest. Newfoundland and Labrador Power Commission had proposed a group rate structure where customers in different communities on the Island Interconnected System would be subject to one of three rates based on different distribution costs. The company argued before the Board at the time that service of the same description supplied at different costs in different areas is supplied under substantially different circumstances and hence rates should be based on the costs of providing the service. In Order No. 29(1968) the Board did not accept this proposal, finding that *"…the proposed Group Rate Structure is unreasonable and unjustly discriminatory and that for reasons of social justice and practicability the Company shall charge uniform rates throughout its entire service area for each class of service…"*.

The Board accepts that there are cost differences between Labrador West and Labrador East. While not confirming the costs as presented by Mr. Drazen, NLH also acknowledged that there are cost differences. The costs in Labrador East are calculated by Mr. Drazen to be in the range of 1.7-2.5 times higher, depending on which COS treatment is assumed for the standby generation in Happy Valley-Goose Bay. (Revised Evidence, M. Drazen, Oct. 3, 2003, pg. 1)

The Board agrees with the opinion of Mr. Greneman however that the fact that there are cost differences does not in and of itself justify separation of the system for rate setting purposes. A sub-dividing of any other geographic area or region on the Island Interconnected System for example would in all likelihood result in cost differences between the two. However the Board would have to be satisfied that there is a valid reason to identify and segregate the different costs for the provision of service before proceeding to develop separate rates for the different areas.

Section 73(1) of the *Act* states:

> *"All tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, and the Board may by regulation declare what shall constitute substantially similar circumstances and conditions."*

When questioned on the applicability of this section, Counsel for the Towns of Labrador City and Wabush stated:

> A. (Mr. Hearn) It's our view that the operative part is *"under substantially similar circumstances and conditions in respect of service of the same description"* and that's why Mr. Drazen does his analysis on costs, which is uncontradicted. We look at the history. We look at the operation. We say that the two separate systems serving Labrador East and Labrador West with different history, different cost base, completely operationally unrelated, that we're into a situation where it's not substantially similar circumstances and conditions in respect of service. It's, in fact, completely dissimilar, and that's the core of our presentation.
>
> (Transcript, Jan. 16, 2004, pgs. 176/21-25; 177/2-12)

The Board interprets Section 73(1) of the *Act* to mean that all customers of a particular utility under substantially similar circumstances and conditions in respect of service of the same description must be charged the same rate. The Board concludes that Labrador West and Labrador East must be considered to be receiving a service of the same description in that they are served by the same generation. The Board further finds that Labrador West and Labrador East must be considered to be receiving this service under substantially similar circumstances and conditions since they are connected to each other and thereby can together be distinguished from the Isolated Systems in the rest of Labrador. The Board accepts the evidence of EES Consulting that it is standard practice for distribution utilities to charge a single rate for the full interconnected system. This approach has been taken by the Board in the past when communities were added to the Island Interconnected System and customers in these communities were charged the same rate as other customers on the Interconnected System. (IC-65)

The COS studies undertaken by NLH for the purposes of setting rates for its Isolated Rural customers embody the principle that substantially similar circumstances do not mean identical circumstances. Although electrically isolated from each other NLH's 24 isolated diesel systems in the Province, both on the Labrador Coast and on the Island, are grouped together for the purposes of COS and setting rates. This approach recognizes that, while not interconnected and in fact widely dispersed geographically, customers in these systems are charged the same rates for the same service under substantially similar circumstances and conditions in respect of service. A consistent approach would lead to the same conclusion for customers in Labrador West and Labrador East.

The Board finds that the Towns of Labrador City and Wabush have not established that the rates for the Labrador Interconnected system proposed by NLH are discriminatory. The Board does not accept that the historical development of the costs of the Labrador Interconnected System should be determinative. The Board is required to observe Section 73(1) of the *Act*. While it may be argued that the historical development or the costs of a system are factors to be considered in the determination of substantially similar circumstances and conditions, the Board notes that the same could be said in respect of a determination for any of the customers of NLH. Each customer or group of customers of NLH could argue that they cause less costs than another customer or group of customers or that the history of the system providing the service is different. The basic goal of cost of service is to determine the relative cost differences between customer classes. The Board is satisfied that the customers on the Labrador Interconnected System are provided service of the same description under substantially similar circumstances and conditions. The Board concludes a single COS study for customers on the Labrador Interconnected System is appropriate as the basis for determining the rates for all customers on that system. NLH's proposals for uniform rates on the Labrador Interconnected System were developed using a single COS study and are therefore appropriately determined.

The Board finds that NLH's proposals for uniform rates for the Labrador Interconnected System are not unjustly discriminatory and rejects the complaint of the Towns of Labrador City and Wabush.

The Board accepts NLH's proposed five year plan to implement uniform rates for Labrador Interconnected customers as set out in its Application. The Board will direct NLH to file for approval a revised Schedule of Rates for each proposed rate change set out in the five year plan.

The Board accepts the proposal that NLH will adjust the Rural Rate Alteration Component of the RSP based on its projection of the five year phase-in of Labrador rates and the revenue credit available from secondary energy sales to CFB Goose Bay with the provision that it be applied only to the portion of the revenue credit applicable to NP and that the rates of the Labrador Interconnected customers not be negatively affected by this adjustment.

VIII. RURAL SYSTEMS

1. Background

NLH owns and operates 24 isolated diesel generating plants serving approximately 4,500 customers throughout Newfoundland and Labrador. On the Island Interconnected System NLH serves approximately 21,800 rural customers in 180 communities along the south coast, northeast coast and the Great Northern Peninsula. The cost of providing service to these approximately 26,300 rural customers exceeds the revenues collected, resulting in the rural deficit. The rural deficit was funded by Government until 1989 and now is funded by means of a cross-subsidy paid by other ratepayers in the Province, in particular NP customers and Labrador Interconnected customers. By virtue of a statutory amendment to the *EPCA*, the IC have not contributed to the rural deficit since 1999.

Order No. P. U. 7(2002-2003) contained several decisions impacting on the rural deficit. These included directing NLH:

- to maintain rural rates equal to NP rates excepting rates above the *"lifeline block"* (700 kWh) for Isolated Rural customers where rate adjustments were to reflect the average rate increase experienced by NP;
- to eliminate preferential rural rates for Federal and Provincial Government departments/agencies while accepting NLH's proposal to submit a plan at its next general rate application to phase out the remaining preferential rates applied to fish plants, churches, schools, community halls, municipal buildings and recreational facilities;
- to implement in its next general rate application a demand-energy rate for general service customers on Isolated Rural Systems and to eliminate the *"lifeline block"* for this same group of customers.

In advance of the hearing Government directed the Board on various matters affecting preferential rates. Other related issues impacting Rural Systems and the rural deficit were raised during the hearing. These issues include the level of the deficit, the lifeline block, rates for general service customers on isolated systems and a proposal from the Towns of Labrador City and Wabush for an energy tax to recover the costs of the rural deficit. A review of each of these issues is outlined below.

2. Rural Deficit

In Order No. P. U. 7(2002-2003) the Board expressed concern relating to the increasing size of the rural deficit and its impact on ratepayers, both those being subsidized and those doing the subsidization. The Board directed attention toward the prospect of this hearing in ordering NLH:

> *"…to assume responsibility for the development of an evidentiary record involving the rural deficit. This record should involve appropriate consultation with Government and should address the magnitude of the rural subsidy, comparative practices elsewhere, as well as future funding options for the rural deficit. The record should also contain a concise statement of other*

public policy initiatives being implemented by NLH on behalf of Government and their associated costs. The Board will require NLH to file this evidentiary record at its next rate hearing."

In response to this directive NLH held several meetings with senior levels of Government and also prepared a Discussion Paper on the rural deficit, which was forwarded to the Deputy Minister of Mines and Energy on March 25, 2003. A copy of the Discussion Paper was filed as part of the pre-filed evidence of Mr. Wells, President and CEO of NLH.

The Discussion Paper outlined the history and magnitude of the rural deficit, rural rate policies, cost control initiatives on Isolated Systems and comparative practices in other Canadian jurisdictions.

Since 1992 the rural deficit has increased by more than 45% as follows:

Rural Deficit ($millions)			
Year	**Rural Island Interconnected**	**Labrador & Island Isolated**	**Total**
2002	17.6	21.2	38.8
2001	12.1	22.0	34.1
2000	6.8	20.0	26.8
1999	5.8	16.3	22.1
1997	7.5	16.4	23.9
1995	4.4	24.9	29.3
1994	3.2	24.5	27.7
1993	4.0	24.0	28.0
1992	4.2	24.7	28.9

(Pre-filed Evidence, W. E. Wells, Schedule II; Discussion Paper on Hydro Rural Deficit Issues, pg. 2)

The rural deficit is expected to grow by approximately 5% through to 2007 as follows (NP-56):

Rural Deficit ($millions)			
	Island Interconnected	**Isolated**[1]	**Total**
2007	$22	$22	$44
2006	$21	$22	$43
2005	$19	$22	$41
2004[2]	$19	$22	$41
2003	$19	$23	$42

[1] The isolated rural deficit is shown in total as it is not available separately by Island Isolated and Labrador Isolated for all years.
[2] Based on the Aug. 12, 2003 revised filing.

The average subsidy in 2002 was $4,600 for each Isolated Rural customer and $800 for each Island Interconnected Rural customer. On the Isolated Systems, an estimated 26 cents of each dollar spent is recovered from customers, whereas on the Interconnected Rural System 64 cents on the dollar is recovered. According to NLH NP pays approximately 19% more than the cost of service as a cross-subsidy to fund the rural deficit. Customers on the Labrador Interconnected System pay 49% more than the cost of service in paying their share of the rural deficit based on the allocation methodology for the rural deficit in the COS study.

The Discussion Paper (pg. 8) also included a summary of the costs and comparative practices of providing service to Isolated Rural customers in Newfoundland and Labrador and other jurisdictions as follows:

Isolated Rural Customers					
Utility[1]	**Communities Served**	**Number of Customers**	**Operating Deficit $millions**	**Average Cost per kWh**	**Deficit per Customer**
ATCO Electric (Alberta)	10	N/A	Not Tracked	21¢	N/A
BC Hydro	9	9,104	28	13¢[3]	$3,076
Hydro One	20	3,691	18[2]	51¢	$4,877
Hydro Quebec	40	13,797	106	45¢	$7,683
Manitoba Hydro	4	791	3	64¢	$3,793
Newfoundland & Labrador Hydro	25	4,463	16[4]	44¢	$3,585
Northwest Territories Power Corp.	51	15,766	0	17¢[5]	0
Yukon Electrical	10	1,300	Not Tracked	N/A	N/A

1 Numbers based on Manitoba Hydro's May 2001 Survey
2 Subsidy amount $17 million
3 Based on costs as of March 2000. Does not reflect increases in diesel prices
4 Based on 1999 COS Study
5 Figures under review… may include non-diesel sites as well.

The table above was updated for Isolated Rural customers based on 2002 data (excepting ATCO Electric and Yukon Electrical) as follows (NP-58):

Updated Isolated Rural Customers		
Updated Data	**Range Indicated**	**NLH-2002 Forecast Cost of Service**
AVERAGE COST PER KWH	15¢ to 341.7¢	53¢
Operating Deficit	$3,000,000 to $116,000,000	$21,000,000[1]
Deficit Per Customer	$3,700 to $9,600	$4,600

[1]The total rural deficit for Isolated Rural and Island Interconnected Rural customers based on NLH's 2002 forecast Cost of Service is $38,758,134

For the most part, residential customers in the above jurisdictions pay the same rates as customers served from the interconnected grid with higher rates applied above a *"lifeline block"* which is defined differently depending on the jurisdiction.

While cross-subsidization is a common practice and for isolated systems the cost of electricity (53¢ per kWh), the operating deficit ($21,000,000) and the deficit per customer ($4,600) is within the respective ranges indicated for other Canadian jurisdictions, NLH's Discussion Paper makes the point that, with its small population base, there are relatively few customers over which to collect the deficit incurred to service Isolated Systems. NLH observed that, at the 1995 inquiry into rural electric service conducted by the Board, NP pointed out in its evidence that *"Hydro's operating deficit for its diesel areas at 8.8% of revenue from electricity sales is by far the largest. Only Hydro Quebec has an operating deficit that is larger in actual dollars but represents only approximately 1% of revenue from electricity sales. B.C. Hydro's operating deficit is also approximately 1%. Manitoba Hydro and Ontario Hydro operating deficits represent about 0.1% or less of revenue from electrical sales.*"

NLH identified a number of initiatives designed to reduce or control the rural deficit, including interconnection of Isolated Systems to the main grid, training a multi-skilled workforce in remote areas, adopting industry recognized best practices for maintaining Isolated Systems, implementing demand side management programs and seeking alternative technologies for generation supply. Where possible, NLH may also decommission plants based on community relocations. Given these initiatives, NLH noted limited opportunity remains to control direct operating costs while maintaining reliable service. NLH observed general inflationary pressures on costs will exceed any increases in revenues, resulting in a deficit which, all else being equal, will trend upward. (Final Argument, NLH, pg. 72)

Recognizing there is a certain amount of subsidization in any system, the CA took no issue with subsidizing rural ratepayers but expressed a concern in relation to the level of rural subsidy. As referenced earlier, the CA submitted it is unfair to use NLH as a tool to implement expensive social policy while expecting ratepayers to pay a further $19,000,000 for a 9.75% ROE. (Transcript, Jan. 16, 2003, pg. 58/4-18) The CA advocated the creation of a separate department to service the Isolated Systems to assist both in tracking the size of the rural deficit and in directing management attention to minimize the deficit while ensuring adequate levels of service. The CA also recommended a management audit to make the deficit more transparent and help alleviate concerns relating to the huge subsidies now being recovered from customers. (Final Submission, CA, pgs. 33-34)

NP noted the rural deficit increases its revenue requirement by 17% and increases by 10% the rates paid by NP's customers. NP commented that, while Government policy for rural rates and the COS assignment of assets are generally outside of NLH's control, NLH can influence the level of the rural deficit by being as efficient and innovative as possible in its operations. Despite NLH's initiatives, NP cited several capital projects which contributed to an escalating rural deficit. NP submitted that NLH should report annually to the Board on the rural deficit detailing its different components, explaining material variances, and providing a five year forecast. (Brief of Argument, NP, pgs. F-1 to F-5)

The IC argued the Board should recommend to Government arrangements for the transfer to NP of all of the rural customers of NLH on the Island, or at least the Island Interconnected customers. The IC concluded such an arrangement would simplify considerably the plant and cost assignment issues which take up so much time before the Board and put the rural deficit issue in an appropriate context. (Written Argument, IC, pg. 39)

The Towns of Labrador City and Wabush noted that passing the burden of the rural rate subsidy only to retail electrical consumers of NP and the Labrador Interconnected System adds annually a much larger amount to the electrical rate paid by those consumers. The Towns of Labrador City and Wabush argued the imposition of the rural subsidy on some electrical consumers in the Province, while exempting others and exempting production exported, is in effect discriminatory against those customers upon whom the burden of the rural subsidy is imposed. The Towns of Labrador City and Wabush proposed that the rural deficit be collected by the imposition of a tax collected on all electrical production in the Province, whether exported or not. (Brief of Argument, Towns of Labrador City and Wabush, pgs. 27-31)

The rural deficit was an issue before the Board in the 1995 hearing on rural electric service, NLH's 2001 general rate hearing and now this Application. With the rural deficit expected to increase because of the widening gap between rural system revenues and expenditures, the rural deficit will continue to present issues for the Board. As noted in Order No. P. U. 7(2002-2003), depending on the level of subsidy paid by one customer to support equitable rates for another customer, the question arises at what point are electrical rates deemed unreasonable and discriminatory to the subsidizing customers?

As in NLH's 2001 general rate hearing, evidence was again heard during this hearing on alternative options to address the rural deficit, including adjusting the shareholders return on equity as well as implementation by Government of a tax on electricity consumption, including exports. In 2001, the Board concluded taxation is a prerogative of Government and is beyond the control of this Board. With regard to a return on equity adjustment the Board was not able to assess in this Decision and Order how NLH's ROE should be impacted by social policy benefits, such as the recovery of the rural deficit, directed by its shareholder, Government.

The Board concludes implementing fair and non-discriminatory electrical rates under the *EPCA*, for both ratepayers subsidizing the rural deficit and those receiving the subsidy, will remain an on-going issue before the Board. Balancing electricity rates between both sets of ratepayers as well as assessing the impact of the rural deficit on ROE will remain recurring regulatory issues. Bearing these prospects in mind, the Board believes the funding of the rural deficit is not only a regulatory concern but is equally a public policy question that should bear the scrutiny of periodic review by Government.

The Board notes the many suggestions concerning the rural deficit made by intervenors during the hearing. These included an annual reporting of costs, a separate management accountability, transfer of NLH's rural customers to NP, determining the impact on the rural deficit of each capital project and a management audit. NLH agreed an annual report of changes in the rural deficit could be provided if deemed appropriate by the Board. None of the other suggestions were supported by NLH. (Final Argument, NLH, pgs. 71-74)

The creation of a separate department accountable for the rural deficit is a managerial consideration for NLH and not a matter which would normally be considered by the Board. The issue of transfer of customers (and assets) between utilities is a complex issue and raises questions of jurisdiction which should be appropriately addressed prior to the Board making any determination.

The Board agrees NLH should strive to minimize the rural deficit through increased efficiencies while ensuring reliable service. These efficiencies should be achieved through continuing initiatives by NLH aimed at reducing operating costs and a diligent cost-benefit analysis of future capital expenditures. The Board finds a detailed annual reporting will assist in monitoring the rural deficit. The Board suggests NLH submit this report to Government possibly in conjunction with its annual report to its shareholder to enable policy oversight.

Given its finding with respect to the annual reporting on the rural deficit, the Board is of the opinion that a management audit as proposed by the CA is not warranted.

The Board will require NLH to submit, in conjunction with its annual financial report, an annual report on the rural deficit which should include the following:

- **i. the total rural deficit and a breakdown of its components by system (Island Interconnected Rural, Island and Labrador Isolated Rural, and L'Anse au Loup);**
- **ii. a five year forecast of the rural deficit by system;**
- **iii. the number of communities and customers served in each system;**
- **iv. the cost per kWh per system, showing a comparison with cost per kWh for the Island Interconnected System (less rural) and the Labrador Interconnected System;**
- **v. the deficit per customer and the cost recovery ratios for each system; and**
- **vi. a summary of any specific initiatives undertaken to reduce the capital or operating costs in each system.**

3. Lifeline Block for Rural Isolated Domestic Customers

For Rural Isolated Domestic customers a block rate structure exists where rates rise as increasing blocks of electricity are used. The purpose of the first lower priced block or "*lifeline*" block is to provide basic electrical requirements such as lighting, cooking, furnace and water pump operation.

The issue of the lifeline block was considered by the Board as part of NLH's 2001 general rate hearing. As noted in Order No. P. U. 7(2002-2003), the Board heard representations from consumers in coastal Labrador during public participation days that the existing lifeline block of 700 kWh per month was inadequate to meet basic electrical needs. The Board ordered NLH to undertake a review of the lifeline block for domestic customers to assess its adequacy.

In December 2002 NLH filed the report A Review of the Adequacy of the Lifeline Block on Diesel Electric Systems, which was revised at the request of the Board and resubmitted March 12, 2003. (CA-13) In this report NLH suggested that a change in the existing lifeline block has merit owing to the continued rise in the market share for electric hot water heating, seasonal electricity use patterns, and the prominence of diesel system customers located in Labrador. Based on a review of household billing data the report proposed an alternative lifeline which would provide for an increased lifeline block of 1,000 kWh per month in the winter, 700 kWh per month for the summer, and a range between 700-1,000 kWh per month for the remaining seasons. If accepted, the proposal would result in an increase in the rural deficit of approximately $66,000 based on the assumptions outlined in NLH's report. (pgs. 8-9)

In July 2003 the Government issued certain directions to the Board under the authority of Section 5.1 of the *EPCA*, and in particular with reference to the lifeline block for rural domestic customers, directed the Board to:

> *"(iii) continue the allocation of a monthly block of energy for domestic residential customers in diesel-serviced communities, and that such service be priced at Newfoundland Power's interconnected domestic electricity rate. The monthly lifeline block should be satisfactory to provide for the necessary monthly household requirements, excluding space heating. Subsequent monthly energy blocks for these customers to be charged incrementally higher rates as historically structured and determined. Such rates would increase as per any percentage increase to Island interconnected rates for Newfoundland Power customers;"*

In its Application NLH did not propose a change in the lifeline block for domestic customers on Isolated Systems. The parties considered this issue as part of the mediation process. The Mediation Report made the following recommendation:

> *"y. Hydro's current three block Domestic Diesel rate structure should be replaced with a two block structure with the first block equal to the Alternative Lifeline and the second block set so as to maintain revenue neutrality. Parties further suggest that, before its formal acceptance of this proposal, the Board seek comment on this matter from affected customers during public participation days in this proceeding."*

NLH incorporated this recommendation in its evidence of October 31, 2003. (Revised Evidence, S. D. Banfield, Oct. 31, 2003, pg. 8) NLH's proposal reflected the recommendation in the Mediation Report with respect to revenue neutrality, which means that any changes to the lifeline block should not increase the amount of the rural deficit paid by NP and Labrador Interconnected customers. NLH proposed that, upon approval by the Board of the alternative lifeline block, the rate schedule for No. 1.2D Domestic Diesel would be modified to incorporate the change.

Information about the alternative lifeline block proposal was sent to participants prior to the public presentations in Happy-Valley Goose Bay. Following the presentations in Happy Valley-Goose Bay the Board directed NLH to provide additional information to those who made presentations as well as to the Mayors of all affected communities. NLH provided this information on December 19, 2003 (Information #21) and, by letter on March 2, 2004, confirmed that no enquiries or comments, either verbal or written, were received on the lifeline block proposal.

In final submission (pg. 43) the CA supported a change in the lifeline block consistent with the three-tier proposal. In an effort to resolve the concerns of those most affected the CA recommended that the proposal be put into effect on a one year trial basis. If residents are satisfied following that one year trial the proposal can be adopted into the future. Lacking such support a new lifeline can be developed which is consistent with the findings of NLH's report.

NLH submitted that the proposal to increase the lifeline block to reflect seasonal usage, without increasing the rural deficit, is a reasonable compromise and meets some of the concerns of the customers with respect to increased consumption in the colder months. NLH leaves the question of whether the lifeline block should be increased or maintained at the current 700 kWh per month to the judgment of the Board. (Final Argument, NLH, pgs. 68/28-31; 69/1-3)

The Board notes that the alternate lifeline block proposal set out in NLH's report, determined from a survey of its rural isolated customers, more closely matches the seasonal consumption patterns of rural domestic customers than the current lifeline block. Currently these customers have access to an annual block of 8,400 kWh (at 700 kWh per month). Under the lifeline block proposed in NLH's report the annual lifeline block allocation will increase to 10,200 kWh, which means that these customers will have access to an additional 1,800 kWh at NP's domestic rate, instead of at the higher energy rate charged for consumption over the existing lifeline block. In the Board's view the proposed lifeline block based on seasonal consumption better reflects the intent of the lifeline block policy, which is to provide for necessary monthly household requirements, excluding space heating.

The Board acknowledges the recommendation of the Mediation Report that any changes to the lifeline block should maintain revenue neutrality and hence not increase the rural deficit. NLH's October 31, 2003 proposal incorporated this recommendation by increasing the rate charged for electricity usage above the lifeline block to recover the shortfall. The Board notes however the wording of the direction from Government regarding the continuance of the lifeline block and, in particular, the direction that "*subsequent monthly energy blocks for these customers be charged incrementally higher rates as historically structured and determined*." The Board interprets this direction to mean that it must continue the existing structure and determination of the rates above the monthly lifeline block. The existing three-tiered block rate structure will therefore be continued with the rates determined as in the past. As directed by Government, the rates above the lifeline block will increase by the average rate change approved by the Board for NP's Island Interconnected customers, consistent with existing policy.

In considering changes to rural rate policies the Board also has to be cognizant of the impact of these changes on the amount of the subsidy that has to be paid by the Labrador Interconnected customers and by the customers of NP. In its report NLH indicated that the implementation of the proposed seasonal lifeline block in conjunction with the existing inverted rate structure would increase the rural deficit by approximately $66,000. As discussed above the Board has been directed to continue the existing rate structure for consumption above the lifeline block and the determination of associated rates. As a result the Board is not able to accept the recommendation of the Mediation Report with respect to revenue neutrality when considering any changes to the lifeline block. However, as the Board is satisfied that the proposed seasonal lifeline block better reflects the necessary monthly household electricity requirements, excluding space heating, for Rural Isolated Domestic customers, the Board finds any corresponding increase in the rural deficit is justified. The Board also accepts NLH's position that this rate structure should remain in place until its next general rate application.

The Board will direct the implementation of a Seasonal Lifeline Block for NLH's Rural Isolated Domestic customers, both Island and Labrador, as set out below:

Seasonal Lifeline Block for NLH Diesel Systems		
Month	**Existing Lifeline (kWh)**	**Alternative Seasonal Lifeline Including Hot Water (kWh)**
January	700	1,000
February	700	1,000
March	700	900
April	700	900
May	700	800
June	700	800
July	700	700
August	700	700
September	700	700
October	700	800
November	700	900
December	700	1,000
Total kWh	**8,400**	**10,200**
Monthly Average kWh	**700**	**850**

Rural Isolated Domestic customers will continue to pay the same rate as NP's domestic customers for consumption within the Seasonal Lifeline Block. The existing block structure for these customers for energy consumption above the Seasonal Lifeline Block will be maintained. The existing policy of automatically adjusting the rates for consumption above the lifeline block by the average rate change approved by the Board for NP will continue to apply.

4. Preferential Rates

A number of general service customers in NLH's Rural Systems, including Government agencies, fish plants, churches and municipal buildings, benefit from preferential rates. In Order No. P. U. 7(2002-2003) the Board found that these preferential rates are discriminatory and ordered NLH to increase rates to the Federal and Provincial Governments to recover the full costs of providing service in rural areas. The elimination of preferential rates for Federal and Provincial Government departments commenced in September 2002, resulting in an estimated annual reduction in the rural deficit of $1,000,000. (Pre-filed Evidence, W. E. Wells, Discussion Paper on Hydro Rural Deficit Issues, pg. 6) The Board also ordered continuation of remaining preferential rates at that time but accepted NLH's proposal to present to the Board at its next general rate application a plan to phase out preferential rural rates.

When fully implemented the elimination of preferential rates on NLH's Rural Systems was estimated to reduce the rural deficit by approximately $2,000,000. (Pre-filed Evidence, W. E. Wells, Discussion Paper on Hydro Rural Deficit Issues, pg. 7) NLH's Discussion Paper showed the targeted cost recovery levels over five years and the impact of rate increases on customers benefiting from preferential rates as follows:

Island Interconnected			
Customer	**Current Recovery**	**Target Recovery**[1]	**Rate Increase**[2]
Burgeo School	41%	100%	144%
Burgeo Library	50%	100%	100%
Isolated Systems			
Customer	**Current Recovery**	**Target Recovery**[1]	**Rate Increase**[2]
Schools Rate 0-10 kW Rate Over 10 kW	 20% 26%	 100% 100%	 400% 285%
Health Facilities Rate 0-10 kW Rate Over 10 kW	 31% 37%	 100% 100%	 223% 170%
Fish Plants Rate Over 10 kW	 17%	 45%	 165%
Churches and Community Halls Rate 0-10 kW Rate Over 10 kW	 21% 25%	 45% 45%	 114% 80%
Other General Service Rate 0-10 kW Rate Over 10 kW	 31% 40%	 45% 45%	 45% 13%
Street and Area Lighting Health Facilities and Schools Regular	 32% 36%	 100% 50%	 213% 39%

[1] Recovery target is the based on the applicable cost recovery level.
[2] Increases are based on preliminary estimates and are subject to change however are believed to be indicative. These increases do not include any general rate increase which would be applicable to all customers.

In July 2003 Government issued certain directions to the Board under the authority of Section 5.1 of the *EPCA*, and in particular with reference to preferential rates directed the Board to:

> "i) *continue to charge fish plants in diesel-served communities and with demand of 30 kilowatts or more the Island interconnected electricity rate;*

ii) *continue to charge churches and community halls in diesel-serviced communities the diesel domestic electricity rate and to continue to charge various customer groups in diesel communities, rates calculated on the same basis as existing practices;*

vii) *continue to charge the preferential electricity rates historically charged to provincial government facilities, including schools, health facilities and government agencies, in rural isolated diesel serviced communities and the Burgeo school and library."*

NLH noted the Board received clear direction from Government that the rural deficit along with preferential rates should continue and furthermore any deficit in serving rural customers as directed should continue to be funded by the customers of NP and Labrador Interconnected customers. (Final Argument, NLH, pg. 71/13-18)

No intervenors commented specifically on preferential rates directed by Government.

The Board acknowledges the direction of Government, under Section 5.1 of the *EPCA*, concerning preferential rates for NLH's Rural customers and the funding of this aspect of the rural deficit, which is to be borne by NP's customers and Labrador Interconnected customers. The Board notes the current cost recovery rate on the Isolated Systems is between 17-40% and preferential rates contribute approximately $2,000,000 annually to the rural deficit. While cross-subsidization to reflect equal rates among similar classes of customers is an accepted regulatory practice, good rate design avoids providing one customer a substantially better rate than another comparable customer receiving an identical service. The Board notes its finding in Order No. P. U. 7(2002-2003) that preferential rates are discriminatory. However, by virtue of the direction received from Government, the Board has no jurisdiction to make any further order with respect to preferential rates.

The Board accepts NLH's proposals for preferential rates for certain customers on the Island Interconnected and Isolated Systems as being in accordance with Government directives.

5. Rates for Isolated General Service Customers

In Order No. P. U. 7(2002-2003) the Board accepted NLH's proposal to address at its next rate application the elimination of the lifeline block for general service (GS) customers on Isolated Systems, in coordination with the implementation of a demand-energy rate structure for those customers.

In July 2003 the Government issued certain directions to the Board under the authority of Section 5.1 of the *EPCA*, and in particular with reference to Isolated GS customers directed the Board to:

> *"(iv) proceed, as the Public Utilities Board determines appropriate, with implementation of a demand/energy rate structure for general service (commercial) customers in diesel communities, where such customers currently pay the diesel general service electricity rate. While the rate changes can include elimination of the lifeline block for these general service customer, the new rates should target the current cost recovery levels for these customers;"*

The implementation of this direction was considered as part of the mediation process. The Mediation Report recommended the following:

> *"h. G.S.2.3 and G.S.2.4 customers on the Isolated Systems should be consolidated into the G.S.2.2 rate class."*
>
> *"i. The proposed three-year phase-in of the demand/energy rate for Rural General Service Customers should be implemented, including elimination of the lifeline block for those customers."*

NLH is proposing 2004 rates for Isolated GS Customers based on the Board's direction in Order No. P. U. 7(2002-2003) and targeting current cost recovery levels for these customers. To mitigate customer impacts NLH proposed that the phase-in of targeted rate components be implemented over three years. NLH also requested that the rates schedules for these customers would automatically come into effect January 1 of each year as outlined in its Application, with the provision that adjustments could be made should a general rate application be filed in the intervening period.

The Board accepts NLH's proposal for rates for Isolated GS Customers as being in accordance with Order No. P. U. 7(2002-2003) and with Government directives as set out above.

The Board will approve NLH's proposal for the phase-in of a demand-energy rate structure, including the consolidation of rate classes and the elimination of the lifeline block, for GS customers on the isolated diesel systems over a three year period. The Board will direct NLH to file for approval a revised Schedule of Rates for each proposed rate change set out in the three year plan. Rates for these customers will continue to be adjusted by the average rate of change granted to NP in any general rate application.

6. Energy Tax Proposal

The Towns of Labrador City and Wabush propose that the rural deficit be collected by the imposition of a tax collected on all electrical production in the Province, whether exported or not, as authorized by Section 92A of the *Canadian Constitution Act*. The rural deficit is, according to the Towns of Labrador City and Wabush, essentially a social tax collected from certain consumers, which is in effect discrimination against those who pay the burden of the subsidy. Other presenters supported the position of the Towns of Labrador City and Wabush during the public presentations in Labrador City, in particular Mayor Letto of Labrador City and Mayor Farrell of Wabush. Mr. Jamie Snook of the Combined Councils of Labrador also supported this proposal during his presentation to the Board in Happy Valley-Goose Bay.

The Towns of Labrador City and Wabush submit that Section 83 of the *Act* gives the Board the authority to recommend the necessary course of action, including legislation, that best ensures appropriate and fair utility rates. Section 83 of the *Act* states:

> "*Where a public utility or person proposes a change in a law relating directly or indirectly to the property or operations of a public utility, the proposed change may be submitted to the board, and the board may take evidence and give public hearings, and the board may recommend the*

> *bills that will in its judgment protect the interests of the public and the public utility, and transmit the bills to the attorney general."*

The Towns of Labrador City and Wabush stated *"…the Board would be in dereliction of its obligation to electrical consumers if it imposed the rural rate subsidy as requested by NLH rather than recommending taxation legislation to include a much wider base on which to impose the burden of such subsidy. It is submitted that the appropriate base is all electrical production of the Province, including that exported from the Province."* (Brief of Argument, pg. 30, para. 87). Effectively, the proposal of Towns of Labrador City and Wabush has two parts:

1) Firstly, the Board should reject recovery of the rural deficit in the manner proposed by NLH; and
2) Secondly, the Board should recommend the introduction of taxing legislation to recover the rural deficit from all electrical production in the Province.

None of the parties to the hearing commented on the Towns of Labrador City and Wabush proposal. In final written submission (pg. 15) Board Hearing Counsel submitted that the Board is not a taxing authority and, since this issue is in the exclusive domain of the Provincial Government, this issue would be more properly addressed to Government.

With respect to the first aspect of the Towns of Labrador City and Wabush request, recovery of the deficit as proposed by NLH, the Board refers to the Government direction to the Board in July 2003. (Appendix C) This direction was again made pursuant to the statutory authority to direct the Board with respect to the subsidization of rural rates, as set out in Section 5.1 of the *EPCA*. The direction specifically states:

> *"Under the authority of section 5.1 of the Electric Power Control Act, 1994, the Lieutenant Governor in Council hereby directs the Board of Commissioners of Public utilities to:*
> *…(v) continue to fund the financial deficit resulting from providing electrical service to Newfoundland and Labrador Hydro's rural customers through the electricity rates charged to Newfoundland and Labrador Hydro's other electricity customers, including its Labrador Interconnected retail customers and Newfoundland Power, but excluding the industrial customers;…"*

This direction confirms the position of the legislature to continue funding the rural deficit in the current manner and removes any discretion of the Board to consider alternatives. By virtue of this direction, made with clear statutory authority, the Board is required to accept the proposals of NLH with respect to the recovery of the rural deficit and must reject the first proposition of the Towns of Labrador City and Wabush.

With respect to the proposal that the Board should recommend the introduction of taxing legislation to recover the rural deficit from all electrical production in the Province, the Board notes that the Towns of Labrador City and Wabush made this same request during NLH's 2001 general rate hearing. The Board rejected this proposal in Order No. P. U. 7(2002-2003), stating that taxation is the prerogative of Government beyond the purview of the Board. Section 83 of the *Act* provides the Board with jurisdiction to recommend legislative changes where a person proposes a change in law relating directly or indirectly to the property or operations of a public utility. The Board does not accept that this section provides the Board with the broad jurisdiction to recommend legislation with respect to the issue of taxation. Therefore, the Board will reject the proposal of the Towns of Labrador City and Wabush to recommend taxing legislation.

The Board will not recommend taxing legislation with respect to the recovery of the rural deficit, as proposed by the Towns of Labrador City and Wabush.

IX. RATES ISSUES/RATE DESIGN

1. Wholesale Demand-Energy Rate to NP

i) Historical Perspective

NP initiated a proposal at NLH's 1990 rate referral requesting a demand-energy rate structure from NLH. The primary concern for NP at the time was the inability of NLH to send the correct price signal through an energy-only rate. NP argued this price signal was of critical importance at the time to design and implement effective demand side management (DSM) programs being contemplated by NP in response to significant forecasted rate increases. In addition NP argued that NLH's rate structure should expressly or implicitly have a demand charge component to track costs more closely. (1990 Report on NLH's Rate Referral, pg. 76) Mr. Brockman, NP's expert witness in this hearing, also appeared as NP's expert witness on this issue during NLH's 1990 rate referral. His opinion on NLH's energy-only rate to NP was summarized in the Board's resulting report (pg. 77):

> *" With an energy-only rate however there are no immediate savings to NLP and its customers for reducing its demand on the Hydro system. Because NLP applies demand charges to its larger customers to control their demands, NLP will actually lose money if those customers respond properly.*
>
> *Another fact that the Board should consider is the effect of the Hydro energy-only rate on NLP rates. It forces NLP to have energy rates that are too high and demand rates that are too low. If NLP is to achieve proper matching between the distinct cost causation effects of demand and energy, the Board should recommend that Hydro develop a rate structure that includes these important components."*

The Board concluded that it was important that NLH present for consideration of the Board a rate to NP with a demand charge component. In its June 1990 report to Government the Board recommended that NLH present at its next rate hearing "*whatever information it may have with regard to a rate with a demand charge component for discussion and determination of a date for filing a rate proposal.*"

In its 1991 rate referral NLH proposed an energy-only rate but filed alternative rate forms for consideration by the Board. In its April 1992 report to Government the Board recommended an energy-only rate for NP but also recommended that *"Hydro and NP develop an acceptable rate form for review by the Board at the hearing to be held on Hydro's cost of service methodology."* At the 1992 generic COS hearing NLH and NP informed the Board that the development of an alternative rate form for NP was not yet finalized but the utilities continued to negotiate on the matter. In its February 1993 report to Government the Board did not recommend a time limit on the submission of the proposed rate form.

The issue was raised again at NP's 1996 general rate proceeding and in Order No. P.U. 7(1996-97) the Board ordered NP to follow the direction given in the Board's 1993 generic COS report and consult with NLH on the development of an acceptable rate form containing an appropriate division of demand and energy costs. The terms of reference for NP's 1998 hearing, which was called on the Board's own motion, stated that the Board wished to receive evidence from NLH on a demand-energy rate for power purchased by NP. At the pre-hearing conference in September 1998 the Board heard representations from NP, NLH, the IC and Government that the recently announced Energy Policy Review to be undertaken by the Government would be dealing with, among other things, existing pricing methodologies and practices, current pricing structures on the Island and in Labrador, future pricing and competition, and average versus marginal cost pricing. It was argued that the planned hearing would duplicate the efforts of the ongoing Energy Policy Review and that the Board should delay consideration of these matters. The Board decided at the time to defer the consideration of those matters, including the development of a demand-energy rate structure for NP.

At its 2001 general rate hearing NLH proposed an energy-only rate for NP, with NLH stating *"Hydro and Newfoundland Power have reviewed this issue and both companies concur that an energy only rate to Newfoundland Power is still appropriate".* NP's position at that time was that *"while a demand-energy rate may be theoretically desirable in many circumstances, introducing such a rate structure into the power purchase arrangement between Newfoundland Hydro and Newfoundland Power is neither necessary nor desirable in the current environment."* [Order No. P. U. 7(2002-2003), pg. 147]

In Order No. P. U. 7(2002-2003) the Board stated:

> *"The Board finds it is not in a position at this time to make a final determination on the issue of whether an energy only rate is appropriate for purchase of power by NP from NLH. The Board has noted the positions of the parties but further evidence will be required from both NP and NLH before making a final decision. If the Electricity Policy Review currently underway does not address this issue as put before the Board at the pre-hearing conference in September 1998, the Board will address it at NLH's next general rate application. At that time the Board will expect NLH to file supporting evidence with its application to address the demand energy pricing issues raised in this hearing."*

ii) Current Application

In this Application NLH proposed an energy-only rate for NP of 53.62 mills per kWh, a 12.0% increase in the base rate currently paid by NP. (Revised Evidence, S. D. Banfield, Oct. 31, 2003, pg. 3/3-10) As directed in Order No. P. U. 7(2002-2003) NLH also filed further evidence regarding a demand energy rate structure for NP with its Application. Stone and Webster Management Consultants, Inc. (SWMC) completed a report Review of Rate Design for Newfoundland Power for NLH. (Exhibit RDG-2) This report addressed the relevant issues in implementing a demand-energy rate to NP and made the following findings (pg. 17):

- An energy-only rate to a wholesale customer the size of NP is an anomaly in terms of current industry practice.
- The ability to send a proper price signal to NP is a key element in controlling island interconnected peak and conserving capital costs.
- In order to send the proper price signal, NLH must accept a degree of risk and the level of risk that NLH assumes should be commensurate with the response in terms of conservation efforts by NP.
- A demand-energy rate can be designed that does not permit a windfall to either NLH or NP due to weather variations.

- A demand-energy rate can be designed that will allow both NLH and NP to achieve virtually the same operational efficiencies as under the current energy only rate structure.

The report recommended that NLH perform analyses for the purpose of establishing a demand-energy rate for service to NP. It also recommended that the results of these analyses be shared with NP and that the proposed demand-energy rate be based on discussions between both utilities. The report did not recommend a specific demand-energy rate design for NP but does provide a Sample Rate design based on the principles outlined in the report. (Exhibit RDG-2, pgs. 15-16)

In respect to questioning from the CA and the Board during cross-examination Mr. Greneman, NLH's COS expert stated:

> A. (Mr. Greneman) …a demand energy rate, even with one customer class is fully justified based upon the fact that I believe it's Hydro's responsibility to pass on its cost as it incurs its financial obligations. And also to encourage load management on the Island to increase the overall efficiency of capital resource allocation on the Island and to lower the use of natural resources when that can be done.
> (Transcript, Nov. 14, 2003, pg. 47/9-17)

> A. (Mr. Greneman) In my view, by virtue of the size of NP and its relationship with Hydro, it is the standard way in the industry for the supplier to sell to a utility, such as NP. I think any other rate form does not get the signal across, is not appropriate for this type of relationship that exists between such large entities. The standard way of doing it is indeed a demand energy rate and in my view nothing else is quite correct.
> (Transcript, Nov. 17, 2003, pgs. 39/19-25; 40/1-3)

In PUB-149 NLH identified the outstanding issues that would need to be resolved before implementation of a demand-energy rate to NP, including: (i) the degree of risk to be assumed by NLH; (ii) an appropriate weather normalization methodology; (iii) the treatment of NP's generation; and (iv) appropriate costing and billing determinants. The types of analyses that should be performed according to NLH include: (i) the effects of variations in NP's hydraulic generation and native load, individually and together; (ii) the effects of varying levels of demand and energy rates; and (iii) quantification of the intrinsic error in the weather normalization formula.

NLH identified a two-month time frame as being adequate to address these issues. Subject to resolution of these issues NLH proposed that a demand-energy rate structure for NP be implemented instead of the energy-only rate as filed by NLH. (Revised Evidence, S. D. Banfield, Oct. 31, 2003, pg. 3/22-28)

In final argument (pg. 84) NLH submitted that there is sufficient information before the Board such that an appropriate demand-energy rate as proposed by NLH could be implemented as of the Order arising from this hearing should the Board desire a demand component as part of NP's rate structure.

NP did not support the implementation of a demand-energy rate structure, and took specific issue with the Sample Rate as proposed by NLH. NP's concerns with NLH's proposal are summarized below: (Pre-filed Evidence, B. Perry and L. Henderson, pgs. 1-2)

- The Sample Rate creates an incentive for NP to modify its seasonal storage patterns to minimize purchase power expense, increasing the likelihood of spillage and thereby increasing the overall cost of providing service to the Island Interconnected System.
- The Sample Rate significantly increases the potential financial impact of forecast variances. The forecast demand and energy variances under the Sample Rate could result in an $8,300,000 decrease in pre-tax earnings, compared to forecast variances of $900,000 under the existing energy-only rate.
- The Sample Rate significantly increases volatility in NP's rate of return on rate base. The return on rate base could be affected by +47 basis points to –77 basis points, exceeding the ±18 basis points allowed by the Board. This could result in rate instability.

NP's position was that the Sample Rate would not benefit customers. According to NP the Sample Rate will not influence retail rate design, will promote less efficient use of generation resources, will not promote cost effective Demand Side Management, and will reduce rate stability. NP stated that continuation of the existing energy-only rate structure is most appropriate.

NP also filed expert evidence which reviewed the existing energy-only rate compared to the Sample Rate proposed by NLH. This report concluded the following: (Pre-filed Evidence, L. Brockman, pg. 1)

- The energy-only rate is superior to the Sample Rate in collecting revenue requirements for a fair return.
- The energy-only rate fairly recovers NLH's cost-of-service revenue requirements from NP.
- A demand-energy rate fairly apportions cost between NLH's Industrial customers, but is not needed for NP, since it is the only customer in its class.
- The current energy-only rate is superior to the Sample Rate in promoting energy efficiency. An inappropriate emphasis on demand charges in the Sample Rate design contributes to inefficiency in the Sample Rate energy charges.
- The energy-only rate allows NLH and NP to optimize the use of their hydraulic and thermal generation resources. The proposed Sample Rate would send an inappropriate pricing signal that would encourage NP to modify its hydraulic storage patterns to reduce costs. NP indicates that the storage modification would increase the likelihood of spillage and result in a less than optimal use of generation resources.
- NP's current rate designs reasonably reflect the Island Interconnected System costs of demand and energy. The Sample Rate will not change NP's rate designs.

- There is no evidence to support additional cost effective demand side management on NP's system. The available evidence indicates that demand management would have little effect on NLH's future generation plans.
- The Sample Rate will encourage NP to spend up to $84 per kWh to reduce peak demand when NLH has provided evidence that $28.20 per kWh is too much to pay for peak demand through interruptible rates.
- The energy-only rate creates a more stable revenue stream for both NLH and NP than the Sample Rate. The energy-only rate, therefore avoids the costs of dealing with additional revenue volatility. There are no benefits to customers of imposing additional revenue volatility on NP.
- Both the Sample Rate and the energy-only rate are understandable for a large customer such as NP. However, the energy-only rate is more practical to administer because it is less complicated.

Mr. Brockman concluded that overall, the current energy-only rate outperforms the Sample Rate when evaluated using generally accepted principles of good rate design. In final argument (pg. E-42) NP summarized its reasons why a demand-energy rate should not be implemented, stating that the movement to a demand-energy wholesale rate would result in increased earnings volatility for the utilities, reduced rate stability for customers, and provide no benefit to customers.

The CA's expert Mr. D. Bowman agreed with the implementation of a demand-energy rate structure for NP and supported the implementation of the rate design as proposed by NLH stating that "*it represents a significant improvement over the energy-only rate in place today.*" (Pre-filed Evidence, D. Bowman, pg. 12/16-17) During direct examination Mr. D. Bowman stated:

> A. (Mr. D. Bowman) …it's widely accepted practice, it's consistent with the principle of ensuring rates reflect costs and a signal cost separately and customer energy demand charges, you should be doing that where it's practical to do so. Now, in that regard, Hydro has proposed a demand energy rate. All the expert witnesses have reviewed it, I think all of the witnesses are more or less in favour with it, in favour of the rate proposed with some minor modifications with the exception—that is with the exception of Newfoundland Power. Newfoundland Power has primarily the same objective it had during the last hearing that related to the revenue stability issue, but I believe there's strong—it meets the primary criterion and that is that it recovers the revenue requirement. It is fair in a sense that it reflects both the services provided by Hydro to Newfoundland Power, that is capacity and energy and it sends an efficient price signal in the sense that an attempt has been made to reflect the fact that demands are higher in the winter and that it's priced close to marginal energy costs on the energy charged. And the over-riding reason is that certainly Newfoundland Power appears to be the outlier in not having a demand energy rate for a customer of this size, so there's strong regulatory precedent to have such a rate.
>
> (Transcript, Nov. 17, 2003, pgs. 46/3-25; 47/1-7)

The IC's experts Mr. P. Bowman and Mr. Osler testified during cross-examination that it would be the norm that large wholesale customers such as NP would have both demand and energy charges. Exceptions noted by Mr. P. Bowman were the Yukon and the Northwest Territories, which involve isolated diesel systems. Mr P. Bowman, the IC's COS witness, stated in cross-examination by NLH Counsel:

> A. (Mr. P. Bowman) Absent a demand energy rate for Newfoundland Power, there is no cost tracking to changes in the peaks it imposes on the system, which is very different than the situation of Industrial Customers where there is some form of cost tracking. It's a striking difference. I'm not sure whether incremental costs is the underpinning for it, as much as just ensuring that rates track cost and relative loads imposed on the system as we go forward. Incremental cost in regards to the demand is somewhat of a more difficult concept, but certainly in regards to tracking the costs of the higher peaks and the relative uses by various customers, a demand energy rate would allow for some form of reflection of the peaks that are imposed by Newfoundland Power in the rates that they pay.
> (Transcript, Nov. 13, 2003, pgs. 115/16-25; 116/1-9)

Prior to considering the issues surrounding the design and implementation of a demand-energy rate for NP, it is necessary to first consider and decide whether a demand-energy rate should be ordered by the Board for NP. This issue has been before the Board since 1990 and NP and NLH have not yet come to an agreement on an acceptable demand-energy rate structure. The Board is satisfied that it has sufficient evidence before it as a result of this proceeding to make a determination on this question.

With the exception of NP's expert there appears to be consensus among the COS experts that the existing energy-only wholesale rate does not reflect accepted cost causation principles. The Board notes the definitive positions expressed by the COS witnesses for NLH, the CA and the IC that a wholesale rate with a demand and energy charge should be implemented by NLH for NP.

The Board does not agree with NP that a demand-energy rate would not provide any benefit to customers. While NP's customers of today may not see any direct benefits in terms of lower rates, the potential for NP to respond to the demand-energy rate by implementing load management programs has the potential in the longer term to result in lower system costs, and hence lower rates. These potential system benefits are important in terms of conserving both capital and natural resources. The Board notes NP has stated that it will not change its retail rate design in response to the implementation of a demand-energy rate. This position is not a determining factor in the Board's decision to approve a demand-energy wholesale rate as part of NLH's rate structure to its customers. After the introduction of this rate structure NP can take whatever steps it deems necessary in the context of its own rate structure.

Based on the evidence, the Board is persuaded that the implementation of a demand-energy rate by NLH for NP's purchased power is appropriate. Such a rate will distinguish between costs incurred by NLH that vary with changes in the system's output of energy, and costs that vary with plant capacity, and therefore the maximum demands on the system. NLH must be prepared to meet and incorporate these demands in its system planning. The potential for improved efficiency on the system and the ability of a demand-energy rate to send a proper price signal by tracking system costs as they are incurred are, in the Board's view, the most important criteria in considering whether a demand-energy rate should be implemented. The implementation of a demand-energy rate is also consistent with the power policy of the province as set out in Section 3(b)(i) of the *EPCA*. This provision stipulates that all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner that would result in the most efficient production, transmission and distribution of power.

The Board acknowledges NP's position on this issue and the potential effects of implementing a demand-energy rate on NP. The Board notes that NP's COS expert Mr. Brockman was not opposed to the concept of a demand-energy rate for NP but disagreed with the Sample Rate proposed by NLH:

> Q. (Comm. Whalen): I take it from your evidence that your summary position is that the sample rate that's been proposed at some point along the way by Hydro, should not be implemented? That's your –
> A. (Mr. Brockman): That's correct.
> Q. I don't get the distinct impression, though, that you're opposed to a demand energy rate for Newfoundland Power, it's the sample rate that you don't –
> A. If the rate were properly designed with taking into account of marginal costs and you could solve the volatility problem, I mean, I would take the same position I think as I took in 1990 that perhaps it is a good idea.
>
> (Transcript, Nov. 18, 2003, pgs. 136/23-25; 137/1-13)

The Board agrees that the evidence supports the conclusion that a demand-energy rate would result in the potential for increased earnings volatility for the utilities. NLH proposed one way of addressing this issue from its perspective with a minimum billing demand set at 98% of the 2004 COS forecast for NP's peak native load less generation credits. The Board does not view the potential for earnings volatility for NP as a reason to not implement a demand-energy rate. The Board notes there are mechanisms available to deal with the variances in purchased power expenses and the impact on NP's earnings if necessary. This is an accepted rate form in most other jurisdictions. The introduction of a demand-energy rate for NP would result in NP facing similar business risk to comparable utilities with the same wholesale rate structure.

As to whether the introduction of a demand-energy rate will result in reduced rate stability for consumers, the Board is not convinced this would be the case. While rate stability to consumers is always an important consideration for the Board, there are mechanisms to deal with rate stability issues if and when they arise. The Board notes there is no evidence to suggest that, absent the RSP, the current energy-only rate would result in more rate stability for consumers than the proposed demand-energy rate.

The Board finds that the introduction of a demand-energy rate by NLH for NP's purchased power is appropriate.

Although the Board has found that a demand-energy rate should be implemented for NP the Board is not convinced that it has sufficient evidence before it to implement such a rate as of this Decision and Order or that the rate could be implemented within the time period contemplated by NLH. In the Board's view there are a number of uncertainties surrounding the design of the demand-energy rate and also with respect to specific issues that need to be resolved between NLH and NP prior to implementation of such a rate. The outstanding issues and the Board's findings are discussed below.

While many of the experts accepted that a demand-energy rate should be implemented, there was insufficient evidence outlining details of an implementation proposal. As set out above, NLH stated in PUB-149 that there were a number of outstanding issues to be resolved before a demand-energy rate could be implemented. However, in oral argument Ms. Greene stated that, with the acceptance of the proposed Sample Rate outlined by SWMC, there were two remaining unresolved issues with respect to the implementation of a demand-energy rate to NP. (Transcript, Jan. 16, 2004, pg. 195/1-25) These two issues, which could be resolved in one month according to NLH, were: (i) ensuring adequate metering was in place; and (ii) agreement on the use of a weather normalization mechanism.

In final argument (pg. E-36) NP stated:

"The introduction of a demand-energy wholesale rate structure for Newfoundland Power would require resolution of the following implementation issues:

1) Design of a reasonable demand-energy rate based upon the characteristics of the Island Interconnected System;
2) Development of a weather normalization methodology for demand;
3) Month of Implementation to ensure calendar year revenue neutrality while moving from the energy-only rate to a demand-energy rate;
4) Creation of a reserve to ensure Newfoundland Power is permitted to recover its annual purchased power expense and earn a just and reasonable rate of return on rate base; and
5) Resolution of some minor metering issues."

NP also argued that any attempt to design and implement a demand-energy rate without a marginal cost study would require the Board to guess at the appropriate demand-energy balance. According to NP the Board should await the completion of a long-run marginal cost study and a retail rate design study, which will incorporate the results of a load research program currently being undertaken by NP. Information from a long-run marginal cost study and a retail rate design study will provide further information to evaluate the efficiency of retail rate designs. (Brief of Argument, NP, pg. E-43)

While the CA and the IC submitted that a demand-energy rate should be implemented immediately they did not discuss the implementation issues raised by both NLH and NP.

The Board is not persuaded that a marginal cost study is needed to design an initial demand-energy rate as the existing 2004 COS study provides the required information. The Board notes the general agreement of the parties, with the exception of NP, on this issue. The results of a marginal cost study when done can be used to reassess the demand-energy rate at NLH's next general rate application in conjunction with other information that will be available.

The Board notes that the Application was filed on the basis of an energy-only rate for NP. The demand-energy rate referred to in the hearing as the Sample Rate was an example of one rate that may be set by the Board if Mr. Greneman's approach were accepted. The Board is not satisfied that the evidence received on the implementation of a demand-energy rate was sufficient to permit the Board to direct that the Sample Rate or some other rate structure be implemented as of this Decision and Order. The Board finds that the issues outlined by both NP and NLH require further exploration before a demand-energy rate can be implemented.

The Board is also concerned that additional issues may arise once the details of a demand-energy rate are considered. The Board notes that the proposed Sample Rate is based on the Greneman Report, which recommends that information should be shared with NP to carefully determine an appropriate demand-energy balance and impacts on revenue streams. (Exhibit RDG-2, pg. 13) The Board is not satisfied that the outstanding issues have been sufficiently addressed to allow the introduction of the rate in this Decision and Order.

The Board will require NLH to file, no later than July 31, 2004, using the embedded COS for the 2004 test year adjusted for this Decision and Order, an application for the demand-energy rate to be implemented for NP on January 1, 2005. The application and supporting documents will fully address, among other things:

- **i. The degree of risk to be assumed by NLH;**
- **ii. The expected relationship between the risk assumed by NLH and the response in terms of conservation efforts by NP;**
- **iii. An appropriate weather normalization mechanism, with quantification of the intrinsic error in the formula;**
- **iv. The treatment of NP's generation as has been determined by this Decision and Order;**
- **v. Appropriate costing and billing determinants;**
- **vi. The use of adequate metering, or, in its absence at any supply points, an appropriate estimation formula;**
- **vii. The effects of variations in NP's hydraulic generation and native load, individually and together; and**
- **viii. The effects of varying levels of demand and energy rates for a range of usage patterns.**

In the meantime, NLH will continue to charge NP an energy-only rate as proposed in its Application, revised to reflect the findings of the Board in this Decision and Order.

The Board encourages NLH to provide NP with the details of the application well in advance of its filing and suggests that NLH and NP meet to discuss implementation issues. Any proposals which are the result of a consensus between NLH and NP should be noted in the application.

2. Interruptible *"B"* Contract for Abitibi Consolidated Company of Canada - Stephenville

From 1993 to March 2003 NLH had an interruptible contract with Abitibi Consolidated Company of Canada in Stephenville. This contract allowed NLH to interrupt 46 MW of capacity at the Stephenville Mill on certain terms and conditions. For this right to interrupt NLH paid Abitibi Consolidated Company of Canada - Stephenville the sum of $1,300,000 annually. NLH did not renew this contract in March 2003 on the basis that, since it has sufficient capacity within its system at present with the new sources of supply that have come on stream, there is no requirement for access to additional capacity through an interruptible arrangement. (Final Argument, NLH, pg. 76/19-27)

The question of whether it was appropriate to terminate the Interruptible B program was identified in the Mediation Report as one of the issues upon which the parties disagree. (Appendix H)

In final argument (pg. 35) the IC requested the Board direct NLH to make available to the IC a curtailable rate on terms and conditions essentially similar to those contained in the Interruptible B contract with Abitibi Consolidated Company of Canada - Stephenville which expired in March 2003. The IC submit that the Interruptible B program was the only significant demand side management effort by NLH and that it should not be discontinued on the basis of a temporary capacity surplus on the system. According to the IC the Stephenville Mill has conformed its operations and practices to accommodate this product and caution that the elimination of the program may potentially make it impractical for the reinstatement of the program in the future. The IC stated:

> *"In advance of a credible and properly reviewed System Resource Plan that assesses both supply and demand side options for the system, it is not now appropriate to terminate a long-term rate offering such as Interruptible B. Continued confidence of both Hydro and its customers in the long term presence of this type of rate offering should not be undermined at a time when, in the next very few years, major decisions on next generating plant must be made…"*
> (Written Argument, IC, pg. 36)

The CA submitted that, although empathetic to the IC's view that the Interruptible B program should continue, no evidence has been filed that would suggest that continuation of this program is beneficial to non-participating customers. As the marginal cost of capacity has not been identified, it is difficult to know the value of the Interruptible B load. The CA recommends that the Interruptible B program should be re-evaluated once the marginal cost of capacity is determined. (Final Submission, CA, pg. 31, para. 93)

NP did not take a position on the specific issue of reinstatement of the Interruptible B contract. The value of the contract itself was an issue in respect to NP's position on the wholesale rate structure and the sample demand-energy rate proposed by NLH. (Brief of Argument, NP, pg. E-33) In oral submissions NP stated that the issue of the Interruptible B rate should be dealt with in the context of a mediated process or generic hearing after NLH has completed a Marginal Cost Study and Retail Rate Design Study. (Transcript, Jan. 16, 2004, pg. 113/18-22)

Board Hearing Counsel submitted that the Board does have the jurisdiction to order the introduction of an interruptible program for a customer as part of the utility's approved rates. (Final Brief, Board Hearing Counsel, pg. 15)

The Board acknowledges the financial impact of the non-renewal of the Interruptible B contract on Abitibi Consolidated Company of Canada – Stephenville, as outlined by Mr. Guillot and Mr. Dean. (Pre-filed Evidence, M. Dean and J. F. Guillot, Sept. 2, 2003, pg. 6/11-15) According to Mr. Dean the loss of the revenue from the Interruptible B contract will result in an additional 7% increase to Abitibi Consolidated Company of Canada - Stephenville on top of the proposed increase of 22.6% resulting from the increase in base rates.

According to NLH the new supply sources (Granite Canal and two power purchase agreements with the Exploits River Hydro Partnership and Corner Brook Pulp and Paper Limited) provide the system with sufficient capacity within its near term planning horizon such that the Interruptible B contract is not needed. This fact is supported by the evidence which shows that the system will not be energy or capacity constrained until the years 2009 and 2011 respectively. (Pre-filed Evidence, J. R. Haynes, pg. 37, Table 8) When the existing agreement was negotiated in 1993 between NLH and Abitibi Consolidated Company of Canada's predecessor Abitibi-Price Inc. the electrical system was in a much different situation. The Board also notes that it does not have any evidence before it to assess the value of such a product to all consumers and whether the rate that was negotiated in 1993 is a fair and reasonable rate.

The Board acknowledges that rate stability is one of the regulatory principles to be considered but this must be weighed against other regulatory principles impacting the issue. The Board agrees with the position of NLH that, based on the evidence, access to power under the Interruptible B rate is not required. The Board finds that there is sufficient capacity in the system at the present time to support the energy and capacity needs of the Province. The Board accepts that Abitibi Consolidated Company of Canada - Stephenville may not be in a position to take advantage of such a rate in the future due to operational considerations but this factor will have to be assessed at that time. Nevertheless cost of service regulatory principles require that costs of regulated operations are prudent as well as used and useful in providing service. Costs associated with providing unnecessary capacity cannot be viewed as satisfying these principles. Therefore, the Board concludes the continuation of the Interruptible B program and/or the addition of a curtailable rate to the IC would be contrary to generally accepted sound public utility practice.

In the Board's opinion the need for and the value of an Interruptible B rate should be considered as part of an integrated planning process, where all alternatives for meeting anticipated system needs, both in the short and long term, are being considered. It is only in this context that the Board can be assured that the system planning is being undertaken on a least cost basis.

The Board will not order NLH to reinstate the Interruptible B rate for Atibiti Consolidated Company of Canada – Stephenville or to make a similar rate available to the IC.

3. Rules and Regulations for Service

In its Application NLH proposed three changes to the Rules and Regulations for Rural Customers consistent with the practice to have its rules and regulations for Rural Customers as similar as possible to those of NP. These proposed changes are outlined below: (Revised Evidence, S. D. Banfield, Oct. 31, 2003, pgs. 17-18)

a. Reduction in the Application Fee for Name Change

NLH is proposing that the wording for Regulation 9(o) be changed as follows:

"An application fee of $8.00 will be charged for all requests for Customer name changes and connection of new services. Landlords will be exempted from the application fee for name changes at Serviced Premises for which a landlord agreement pursuant to Regulation 11(f) is in effect."

b. Elimination of Statement Preparation Fee

NLH is proposing to remove clause 9(n) which charges a customer for the preparation of account statements for billing information prior to the most recent twelve months.

c. Extension of the Reconnection Fee

NLH is proposing to change its regulations to permit charging the reconnection fee to new customers where a reconnection of service is required subsequent to a request by a landlord to disconnect an apartment. New customers in apartments that are required to pay the reconnection fee will not be required to pay the application fee. NLH is proposing the following wording for Regulation 9(f):

"Where a service is Disconnected pursuant to Regulation 12(a), b(ii), (c), or (d) and the Customer subsequently requests that the service be reconnected, the Customer shall pay a reconnection fee. Where a Service is Disconnected pursuant to Regulation 12(g) and an Applicant subsequently requests that the service be reconnected, the Applicant shall pay a reconnection fee. Applicants that pay the reconnection fee will not be required to pay the application fee. The reconnection fee shall be $20.00 where the reconnection is done during normal office hours or $40.00 if done at other times."

A new clause 12(g) that defines disconnecting a service as a result of a landlord agreement will be added, as follows:

"Hydro may disconnect the Service to a rental premises where the landlord has an agreement with Hydro authorizing Hydro to disconnect the Service for periods when Hydro does not have a contract for Service with a tenant of that premises."

These proposed changes to the Rules and Regulations were the subject of the Mediation process and were agreed to by the parties in the Mediation Report. (Appendix H) The Board accepts the recommendations of the Mediation Report and further notes that the proposed changes are similar to those approved by the Board for NP in Order No. P. U. 19(2003). The Board supports consistency where possible in the application of Rules and Regulations to customers of NLH and NP.

The Board accepts NLH's proposed changes to the Rules and Regulations for Rural Customers.

4. Rate Change/Implementation

NLH requested that the rates to be implemented based on the Board's final ruling be effective for consumption on and after the implementation date as ordered by the Board and be the same rates as would have been effective on January 1, 2004, other than for Labrador Interconnected firm customers and Isolated Rural Customers. NLH proposed that the rates for Labrador Interconnected firm customers and Isolated Rural customers be effective for bills issued on and after the implementation date as ordered by the Board and be the same rates as would have been effective on January 1, 2004. (Final Argument, NLH, pg. 88)

In order to determine the final base rates to be charged customers, NLH will have to complete a final COS study incorporating any changes required as a result of this Decision and Order. In final argument (pg. 88) NLH proposed that the final COS be as filed in its revision dated October 31, 2003, adjusted to reflect only any 2004 capital budget additions that might be approved by the Board further to NLH's application of November 21, 2003, and the Board's findings in this Decisions and Order. NLH stated that it will circulate the final COS study flowing from the Board's Order to the parties. (Transcript, Jan. 16, 2004, pg. 49/12-15)

The Board acknowledges NLH's proposal that the rates to be implemented as a result of this Decision and Order be the same rates as would have been effective January 1, 2004, as proposed in its Application. Due to the timing and length of the hearing, implementation of rates as of January 1, 2004 was not possible. The effect of NLH's proposal is that its customers will not pay the full costs for electrical service for the 2004 test year, and hence NLH will not recover its revenue requirement for 2004. The Board is therefore cognizant of the effect on NLH of any future delay in implementing the rates that will flow from this Decision and Order. NLH has indicated that it will require approximately 4-6 weeks to complete an updated COS study and to re-file revised rates for the Board's consideration. Given the timing of this Decision and Order July 1, 2004 is, in the Board's view, the earliest and most practical date to implement rate changes for all customers. This date will also coincide with the RSP adjustment for NP's customers.

In order to finalize rates to be implemented as a result of this Decision and Order, NLH will be required to incorporate the decisions of the Board by:

- **i. adjusting its revenue requirement and calculation of rate base and rate of return on rate base;**
- **ii. revising its October 31, 2003 COS study for the 2004 test year;**
- **iii. revising its proposed Schedule of Rates for the various customer classes based on the updated COS; and**
- **iv. addressing the consumption on which the rates will be effective for the bills of NP, the IC, Labrador Interconnected firm customers, Island Interconnected Rural Customers and Isolated Rural Customers;**

and filing the above with the Board for approval.

X. OTHER ISSUES

1. Regulatory Oversight – Planning, Performance Measures and Reporting

In Order No. P. U. 7(2002-2003) the Board requested Grant Thornton to work with NLH to recommend suitable regulatory performance standards which would be used to measure operating efficiencies at NLH and form part of NLH's ongoing reporting to the Board. Grant Thornton's report Report on Regulatory Performance Measures for Newfoundland and Labrador Hydro was filed with the Board on July 17, 2003. (Information #4)

Grant Thornton noted NLH currently reports several performance indices to the Board on both a quarterly and an annual basis as part of its ongoing regulatory reporting requirements. The quarterly reports currently include statistics for System Average Interruption Frequency Index (SAIFI), System Average Restoration Index (SARI) and System Average Interruption Duration Index (SAIDI). NLH also reports annually the Derating Adjusted Forced Outage Rate (DAFOR), Weighted Incapability Factor and Customer Satisfaction Index. These performance indices primarily focus on the reliability of NLH's service. Grant Thornton recommended that these performance measures continue to be reported in the manner and frequency in which they have historically been provided to the Board.

In its report Grant Thornton identified other key performance indicators (KPIs) which were suggested would be of value and interest to the Board from a regulatory perspective. Grant Thornton recommended that NLH report annually to the Board on these additional KPIs listed below:

- Thermal conversion factor (MWh generated at Holyrood per barrel of oil-MWh/bbl);
- Hydraulic conversion factor (MWh generated per million cubic meters of water – MWh/MCM);
- Corporate operating, maintenance and administration expense (OM&A) per MWh generated;
- Generation OM&A per MWh generated;
- Generation OM&A per MW installed capacity;
- Transmission OM&A per km of transmission line; and
- Distribution OM&A per rural customer or per km of distribution line.

NLH proposed in final argument (pgs. 33-34) that the Generation OM&A should be measured on a per MW basis and not a per MWh basis as proposed in the report. Mr. Brushett stated that this proposed change did not cause him any major concern but that he was not certain if the performance measures found in the COPE database, which has been used as an information source and which would be used for comparison, contained a performance measure for OM&A per MW of installed capacity, but that there is one for MWh generated. (Transcript, Dec. 11, 2003, pg. 32/1-14)

Grant Thornton indicated that industry or inter-utility comparisons combined with internal benchmarking would provide better data for purposes of monitoring performance and targeting continuous improvement. Grant Thornton recommended that NLH review and propose to the Board appropriate industry or inter-utility comparisons for all recommended KPIs on which NLH has been directed to report. This recommendation was supported in the Mediation Report, where the parties agreed, inter alia, that

> *"aa. Hydro will propose a peer group of utilities and measures upon which to compare its performance not later than six months following the date of the Board Order in this proceeding. Upon approval thereof, Hydro will collect and report such measures for itself and the peer group annually beginning in 2005".*

The Board agrees with the recommendations of Grant Thornton with respect to the establishment of additional KPIs to be included as part of NLH's regulatory reporting to the Board. The measures as proposed will assist the Board in monitoring NLH's operational efficiencies. The Board also believes that the addition of the performance measure suggested by NLH (Generation OM&A per MW) would be useful to the Board in that it would provide another, but less volatile, measure of generation OM&A costs.

The Board also agrees that external benchmarking of NLH's KPIs to industry data or specific inter-utility comparisons will be of value to the Board. The Board accepts the recommendation of the Mediation Report regarding the establishment and reporting of performance measures based on a *"peer group"* of utilities. This is consistent with the Board's direction in Order No. P. U. 19(2003) in which NP was ordered to file a report suggesting a *"peer group"* of utilities upon which the Board can compare performance.

In recommending these KPIs Grant Thornton submitted the objective of KPI measurement is to establish an effective regulatory framework and process for monitoring NLH's operating efficiency on a go forward basis. With a view to achieving this objective, Grant Thornton recommended that NLH be asked to submit annual targets (or objectives) for each KPI being reported to the Board, together with the background support or rationale for the targets. Grant Thornton suggested the targets should be supported by or linked in some manner to certain business process improvement initiatives or arise from certain benchmarking analysis or inter-utility comparisons of performance. (Supplementary Evidence, Grant Thornton, Dec. 5, 2003, pg. 2/5-12)

Mr. Wells described the *"strategic direction"* taken by NLH, commencing in January 2000, as an effort to "*...optimize performance in all activities throughout the corporation."* In describing the process to be undertaken by NLH, Mr. Wells stated that, *"Corporate performance is to be optimized through an assessment of business processes and the identification of changes necessary to improve performance as measured through the development of process metrics and implementation of key performance indicators".* (Pre-filed Evidence, W. E. Wells, pg. 19)

NLH's approach to optimizing corporate performance as described by Mr. Wells is consistent at a conceptual level with the Board's objective of ensuring NLH is operating in a manner that results in the *"most efficient production, transmission and distribution of power at the lowest possible cost."*

Mr. Wells explained that this is not a program that will end. He described the process as ongoing and one that will make *"...the Hydro of 2005... absolutely nothing like the Hydro of, say, 1999 or 1998."* (Transcript, Oct. 7, 2003, pg. 97/2-4)

In response to questions from the Panel, Mr. Brushett stated that *"In terms of Process Improvements Initiatives and so on, it would be common practice to outline what the objectives were and try to quantify that...and what the outcome should be at the end of the day".* He added that in undertaking such a large initiative it would certainly be expected that you would set out some objectives. (Transcript, Dec. 11, 2003, pg. 162/6-18)

During cross-examination by NP, Mr. Brushett stated:

> A. (Mr. Brushett) I think if you review some of the evidence, the pre-filed, as well as some of the examination of Hydro witnesses, there has been discussion about specific projects and how they translate into savings on a go-forward basis. However, there's also evidence suggesting how does this all tie together? What are you targeting for efficiency improvements? And where is that information in terms of your targets or your expected improvements, factored into this whole application and forecast?
> (Transcript, Dec.11, 2003, pgs. 92/19-25; 93/1-6)

In response to NP's question as to whether NLH should have some kind of overall plan, Mr. Brushett replied that, from a regulatory point of view the process is not transparent and NLH should be submitting targets which fall out of the overall plan. (Transcript, Dec. 11, 2003, pg. 97/8-16)

A large organization, such as NLH, would be expected to have a strategic plan with clearly defined goals and objectives, which is supported by a comprehensive business/operational plan. It is the Board's understanding, based on the evidence, that NLH has either completed or contemplated many of the elements that one would expect to see in a strategic/business planning process. These include reference to strategic considerations, KPIs, business improvement processes and accountable business units. The Board has not seen a comprehensive plan from NLH that clearly integrates the overall corporate goals and strategies and the various specific process improvement initiatives referenced during the hearing.

Order No. P. U. 7(2002-2003) stated:

> *"The Board believes the onus is on NLH to bring forward measures which clearly demonstrate the efficiency of its operations. This perspective was not presented into evidence before the Board in any of the normal business performance measures, either overall corporate performance, cost efficiencies or business unit accountability. There was also no indication that NLH had any of these performance measures/targets/objectives built into its existing business systems or was contemplating their implementation in relation to the strategic or business planning exercise currently underway."*

The linkage between sound planning and performance, more appropriately called accountability, is a key element in the regulatory oversight of the Board. This linkage remains a concern of the Board in this Application as it was previously. Now that suitable performance measures have been established and other strategic components are now in place within NLH, the Board feels the timing is appropriate to bring these pieces together into an appropriate regulatory accountability and reporting framework. The Board acknowledges that this process is substantial but should serve the interests of both NLH and the Board.

The Board will require NLH to incorporate the following KPIs into its annual reporting to the Board, commencing with its 2004 annual report.

- **i. Thermal conversion factor (MWh generated at Holyrood per barrel of oil- MWh/bbl);**
- **ii. Hydraulic conversion factor (MWh generated per million cubic meters of water – MWh/MCM);**
- **iii. Corporate operating, maintenance and administration expense (OM&A) per MWh generated;**
- **iv. Generation OM&A per MWh generated;**
- **v. Generation OM&A per MW installed capacity;**
- **vi. Transmission OM&A per km of transmission line; and**
- **vii. Distribution OM&A per km of distribution line.**

The Board will direct NLH to propose to the Board for approval a *"peer group"* of utilities for the purposes of external benchmarking of its KPIs.

The Board will direct NLH to file by December 31, 2004 a report outlining:

- **i. a comprehensive description of NLH's strategic and business planning processes;**
- **ii. a description of how corporate goals and strategies are communicated and operationalized, including how specific operational targets are identified and linked to corporate goals and strategies; and**
- **iii. a description of how management performance and employee incentives are tied to achieving targeted goals, outcomes and efficiencies.**

The Board will direct NLH to file annually, commencing with its 2004 annual financial report, a report outlining:

- **i. a strategic overview highlighting core strategies, corporate goals and achievements;**
- **ii. appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes/measures, including the KPIs as set out above; and**
- **iii. initiatives targeting productivity or efficiency improvements, including the status of ongoing projects and improved performance resulting from completed projects.**

2. Marginal Cost Study

The issue of the need for completion of a marginal cost study was raised by some of the parties to the hearing, both in the context of the discussion of the demand-energy wholesale rate and also with respect to demand side management and other rate design issues. This issue was also raised during NLH's 2001 general rate hearing. The Board determined at that time that it would not be timely to commence a marginal cost study given the many issues arising from that proceeding and also in light of the fact that the Electricity Policy Review was ongoing. In this proceeding the CA and NP have specifically recommended that NLH be required to complete a marginal cost study. The question of whether NLH should be required to undertake a marginal cost study was identified in the Mediation Report as one of the issues on which the parties disagreed. (Appendix H)

In final argument (pg. 32) the CA recommended that the Board direct NLH to undertake a marginal cost study and evaluate and make recommendations on how its rates can be re-designed to better incorporate marginal cost principles and promote market efficiency. The report should make specific recommendations regarding the introduction of rate options for customers and include a time bound plan for implementation. This recommendation is consistent with the CA's position during NLH's 2001 general rate hearing.

NP dealt with the issue of marginal costs in the context of the demand-energy wholesale rate, arguing that if such a rate is to be implemented long-run marginal cost information is required to properly design the rate. NP's position is summarized in its final argument (pg. E-42):

> *"A long-run marginal cost and retail rate design study is required to permit implementation of cost effective DSM and to evaluate the efficiency of retail rate designs. NP would review the results of the study to determine what action, if any, is required in the areas of rate design and DSM. NP is currently undertaking a load research program that will provide usage pattern information to be used in evaluating the fairness of its retail rate designs. NP currently uses the short-run marginal costs as an input in rate design. Information from a long-run marginal cost study and a retail rate design study will provide further information to evaluate the efficiency of retail rate designs."*

In final argument (pg. 77) NLH stated that, if the Board sees merit in completing a marginal cost study, it is prepared to undertake the study to address long-term generation and transmission expansion and outline recommendations on resulting industrial and wholesale rate options. NLH stated that a second part of the study would need to be completed by NP which would incorporate the results of NLH's analysis of distribution costs which would then provide recommendations and result in retail rate options for NP's customers.

The Board has already determined that a marginal cost study is not necessary in order to implement a demand-energy wholesale rate for NP. The Board is satisfied, however, that NLH should undertake a marginal cost study. NLH has not undertaken a marginal cost study or a time differentiated embedded cost study since 1992. (NP-141) NLH's response to IC-185 indicates that consideration of rate options for the IC such as time-of-use and seasonal rates requires marginal cost information. NLH's response to NP-167 indicates that demand side management programs should be evaluated on a marginal cost basis with the constraint being revenue lost. In the Board's view a marginal cost study is also necessary to address some of the issues that were raised in this hearing, such as the value of the Interruptible B load, and NP's curtailable service option. In addition, as suggested by most of the COS experts, the results of the marginal cost study can be used to confirm the level of the demand rate for NP's wholesale demand-energy rate.

The Board recognizes that there must be an exchange of information between NLH and NP in order to successfully complete this study. It therefore expects that this study will take place in an open and co-operative manner. If problems are encountered that may delay the completion of the study, NLH is expected to seek further direction from the Board. Both utilities will be required by the Board as part of its general supervision of the utilities to provide quarterly updates as the study progresses.

The Board will direct NLH to undertake and file with the Board no later than June 30, 2006 a marginal cost study. NLH will be permitted to recover its reasonable costs associated with this study and may accumulate these costs in a deferral account to be dealt with at its next general rate application.

3. Future Supply/Integrated Resource Planning

Since NLH's 2001 general rate application three new sources of supply have been added to meet the forecast load requirements for Island Interconnected customers. These include the Granite Canal project and two power purchase contracts with Abitibi Consolidated Company of Canada relating to the Exploits River Hydro Partnership, and with Corner Brook Pulp and Paper Ltd. A wind generation project on the Burin Peninsula is also currently under development. These projects were exempted from the jurisdiction of the Board by government direction.

Mr. Wells acknowledged that, absent an exemption from government, the Board has jurisdiction with respect to new sources of supply. He stated:

> A. (Mr. Wells) Hydro is not the decision maker. We may make representations with respect to the new source of supply, but it's not Hydro's, in our authority. It's under the statutory authority to ensure that the island's energy--or the Province's provincial energy requirements are met are set out and it's the Public Utilities Board jurisdiction. They can decide and Government could, by Order in Council, decide, but not Hydro. It's not us to decide that it's going to be Island Pond or Granite Canal or anything else. It's not our decision.
>
> (Transcript, Oct. 9, 2003, pg. 160/14-23)

Mr. Wells' view is consistent with the provisions of the *EPCA* which sets out the Board's jurisdiction in relation to new sources of supply. Section 4 of the *EPCA* requires the Board to implement the power policy of the province as set out in Section 3 and includes the provision that:

> *"all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner ...(iii) that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service..."*

Section 6 of the *EPCA* further states that:

"(1) The public utilities board has the authority and the responsibility to ensure that adequate planning occurs for the future production, transmission and distribution of power in the province.

(2) The public utilities board may direct a producer or retailer to perform such activities and provide such information as it considers necessary for such planning to the public utilities board or to any other producer or retailer on such terms and conditions as it may prescribe."

It is clear that the authority and responsibility rests with the Board to ensure that adequate planning occurs for the future production, transmission and distribution of power in the province. In addition the *EPCA* mandates that supply options result in the lowest cost electricity consistent with reliable service. In planning for future supply, the Board has the discretion to take the appropriate steps to determine that, in planning for future supply, all available options are canvassed and that the options chosen result in least cost service. The Board must be satisfied that all reasonable and necessary steps have been taken to ensure that the Board can appropriately discharge its legislative mandate with respect to future supply.

According to the pre-filed evidence of Mr. Haynes (pg. 37, Table 8) there will be energy and capacity deficits in 2009 and in 2011 respectively. Mr. Haynes described the process that generally would be followed to evaluate the options for future supply and of making a proposal to the Board for review and approval of the most economic outcome that meets the reliability criteria that have been adopted. Mr. Haynes agreed that planning must start in 2005 to meet this forecast demand and that the options for future supply currently include Island Pond, any new generation sources that might result from the issuance of a Request for Proposals, or an additional unit at Holyrood, with the latter being the least likely at this time. (Transcript, Oct. 23, 2003, pgs. 171/23-25; 172/1-7; 173/18-25; 174/1-10)

It is not clear to the Board from the evidence as to what process NLH intends to follow in planning for future supply, which by its nature is a process which may take many years to complete. The Board notes that only one of the new sources of supply- Granite Canal - was addressed in NLH's near term planning document, <u>Generation Expansion Study of Near Term Options for Meeting Newfoundland's Load Growth, November 1999</u>. (CA-36) Time constraints have been a factor in the issuance of government exemption for new sources of supply in the past. Mr. Wells, in explaining why an Order-in-Council was issued to exempt Granite Canal from the jurisdiction of the Board, described the prospect which arose in 2001 for a smelter located on the Island relating to the Voisey's Bay Project. As a result of the delay caused by the consideration of this project, NLH had to quickly address the forecasted demand on the system. (Transcript, Oct. 10, 2003, pgs. 78/18-25; 79/8-25)

During the hearing a number of witnesses made reference to Integrated Resource Planning, its goals and some of its components. The IC recommended that NLH undertake a process of Integrated Resource Planning. (Written Argument, IC, pg. 45) Board Hearing Counsel submitted that system planning, long run marginal cost, and demand side management issues are best dealt with in the context of an Integrated Resource Plan. Mr. Brockman agreed that the views of stakeholders regarding supply side costs, demand side issues such as demand side management, including interruptible and curtailable rates, rate design and issues of fairness would be very important to this process. (Transcript, Nov. 18, 2003, pgs. 113-125) A marginal cost study was identified by both EES Consulting and by Mr. Brockman as being necessary for Integrated Resource Planning. (Transcript, Nov. 19, 2003, pg. 58/16-21; Supplementary Evidence, L. Brockman, Nov. 6, 2003, pg. 2)

The Board accepts that the implementation of Integrated Resource Planning may present sound opportunities for coordinated planning and improved regulation involving both utilities. The process brings together strategic planning, future supply and demand, least cost analysis, demand side management options and environmental considerations. While issues surrounding Integrated Resource Planning were raised in this proceeding, more detailed information is required before the Board can move forward with Integrated Resource Planning. It is also apparent that these issues cannot be effectively addressed in the context of a general rate application of one utility. The Board concludes that Integrated Resources Planning is a complex regulatory issue which should be considered in the context of a generic process involving both utilities and other interested parties. This process would allow the Board to address methodologies, benefits, costs and scheduled implementation associated with Integrated Resource Planning.

The Board has authority and responsibility to ensure that adequate planning occurs for the production, transmission and distribution of least cost reliable power in the Province. While the Board will make no order at this time with respect to Integrated Resource Planning, the utilities may be required by the Board, consistent with its mandate, to participate in a generic process to address issues and benefits associated with Integrated Resource Planning.

4. Demand Side Management/Conservation

Demand Side Management (DSM) is the term used to describe all activities or programs undertaken by an electric utility or by its customers to influence the timing and amount of electricity use, in an effort to shift demand to off-peak times, reduce peak, or reduce overall energy consumption. It may make use of more direct tools, such as water heater controls, or more indirect tools, such as rate design, and it is generally targeted at one or more of the following categories: (i) Conservation; (ii) Load Management; (iii) Fuel Substitution; (iv) Load Building; and (v) Self-Generation. (Pre-filed Evidence, L. Brockman, Exhibit LBB-4, pg. 1)

The benefits that can result from successful DSM programs include savings from fuel not burned at power plants in the short term, and resources saved from not building load serving facilities in the long term.

The issues of DSM and conservation have been raised in every public hearing involving NLH and NP going back to the energy crisis brought on by rapidly escalating fuel prices in the late 1970's. While both utilities have initiated conservation and DSM programs in specific communities and for limited time periods there has not been any coordinated, long-term approach to address the issues in a meaningful way.

As a result of the evidence presented in Order No. P. U. 7(2002-2003) the Board ordered NLH to file, with each application for approval of capital expenditures in rural isolated systems where generation is being replaced or upgraded, a cost benefit analysis of alternatives that might result in reduced load or deferral of capital expansions, including appropriate conservation or DSM programs. Since the issuance of Order P. U. 7(2002-2003) these cost benefit analyses have regularly been included with relevant applications.

NLH was also ordered to file, on or before December 31, 2002, a multi-year plan directed towards its community-based conservation initiatives. This report was received by the Board on December 12, 2002, and was filed in this hearing in response to CA-20. NLH's plan indicates that a professional consultant has been engaged to assist with the development of an appropriate program and promotional activities focused on encouraging customers *"to identify with and embrace the concepts of energy conservation"*. The multi-year plan is called Hydrowise, and its primary purpose is to identify opportunities for customers to manage their electricity bills by helping them understand electricity usage in their homes and businesses. The long-term goals of the program are to use continuous education and promotion and customized information to:

- modify attitudes and behavior;
- focus greater attention and interest on energy conservation; and
- provide a program that is recognizable and accessible and that will assist customers to enjoy a more comfortable living environment; and reduce their energy costs.

The program has a multi-year phase-in schedule and NLH intends to evaluate the plan by tracking various statistics on customer participation and by customers' ratings in the Annual Customer Satisfaction Survey.

In this hearing the issue of conservation and DSM was addressed during public presentations and in the context of discussions regarding the demand-energy rate for NP, the need for a marginal cost study, and the link between these and proper price signals that would influence the implementation of DSM programs.

The availability of new tools to assist consumers in making wise use of electricity was illustrated during public presentations on December 8, 2003 in a well-constructed presentation by Mr. Maurice Tuff and Mr. Danny Tuff of Blue Line Innovations Inc. In an effort to provide real time feedback to consumers Blue Line Innovations have developed a programmable power cost meter that can predict, based on current usage and the current rate, what the monthly bill will be. According to the presentation the meter is simple to install, is affordable in that it will retail for less than $100, and is currently the subject of an agreement with NP whereby it will be installed as a test unit in the homes of 100 of NP's customers. Mr. Maurice Tuff indicated that studies have been carried out on the use of the power cost meter and he feels confident that "*anyone who uses one of these will conserve over 10 percent."* (Transcript, Dec. 8, 2003, pgs. 23-24)

In final argument (pgs. 35-39) the CA expressed his disappointment with the Hydrowise program and with the lack of initiative shown by both utilities in this province. He asked that the Board direct NLH to embark upon a conservation program with specific targets and objectives.

He summarized the positions of several consumers who made presentations to the Board during the hearing regarding their interest in conservation, consumer education, rate design aimed at providing price signals to consumers, the activities of the Climate Control Plan for Canada, billing improvements to provide more detailed consumer information, and the role of the Board in promoting conservation. He did express approval of innovative technology such as the power cost meter developed by Blue Line Innovations Inc. and suggested that the Board should remain appraised of and support this initiative.

NP stated that DSM programs which result in higher rates over the long term should not be implemented. NP submitted that proving the existence of effective DSM programs is a complicated undertaking requiring the use of specific methods of evaluation. NP agreed with the direction in Order No. P. U. 19(2003), issued on completion of NP's 2003 general rate hearing, whereby the Board concluded that determining a policy direction on DSM is complex and is best dealt with in a generic hearing. (Brief of Argument, NP, pg. E-15)

Board Hearing Counsel stated that the principal objective of any DSM program is to ensure that resources are being used in the most efficient manner possible and that this requires knowledge of system planning and the long-run marginal cost of supplying energy and capacity. It was suggested that conservation and DSM are best addressed as part an integrated resource planning process.

In its final argument (pgs. 86-87) NLH submitted that specific targets regarding demand reductions are not appropriate with respect to the Hydrowise program, that its activities in the conservation area are appropriate, and that no further action is required at this time.

The Board reiterates the conclusion reached in Order No. P. U. 7(2002-2003) and Order No. P. U. 19(2003) that conservation and DSM initiatives are important issues with respect to least cost electricity for consumers in the Province. The Board previously noted the relationship between rates and electricity consumption and the impact of DSM and energy efficiency programs is complex, especially when considering the impact on future generation. The evidence presented during this hearing again illustrated problems that arise in determining what programs are cost-effective, provide material benefits to consumers and actually reduce or defer capital expansion over the long term. As concluded with reference to hearings into previous general rate applications of both NLH and NP, the Board was presented with insufficient evidence to enable it to provide specific and meaningful direction to the utilities in respect of DSM issues. For this reason, Order No. P. U. 19(2003) resulting from NP's latest general rate application stated:

> *"This matter would be most appropriately addressed in the context of a generic proceeding involving both utilities and interested parties. The Board will consider the manner and timing of such a proceeding following the hearing of NLH's general rate application."*

Following the completion of this hearing, the Board confirms this position and the Board will now consider the manner and timing of a generic proceeding on DSM. The Board also notes that DSM is an integral part of Integrated Resource Planning as outlined in Part II - Section X of this Decision and Order and the preliminary consideration of DSM may reasonably form a part of any proceeding into Integrated Resource Planning.

The Board encourages NLH to continue to raise consumer awareness and develop/implement programs aimed at energy efficiency and conservation. The Board will not direct NLH at this time respecting DSM initiatives but will consider the manner and timing of a generic proceeding which will address DSM options and impacts on the overall system.

5. Other Mediation Report Issues

The following agreed upon issues were also identified in the Mediation Report but have not been dealt with elsewhere in this Decision and Order:

> *"z. Hydro will work with the CA to redesign its rural customer survey to gather information on customer valuation of service quality versus the costs incurred to improve and maintain service quality, with the results to be reported to the Board in time for incorporation in Hydro's 2004 customer survey.*
>
> *cc. Parties request that the Board prepare or obtain a report on Performance Based Regulation (PBR) alternatives for Hydro and NP, with input solicited from all interested stakeholders prior to finalization of the Report, and opportunity for comment and discussion in considering the final Report."*

With respect to the issue of the redesign of NLH's rural customer survey the Board is not compelled to direct NLH on this matter. While the Board acknowledges the parties' efforts in the Mediation Process, it is difficult for the Board to accept a recommendation from the parties absent any other background information or other evidence to support it and to enable the Board to make an informed decision. While the Board will not order NLH to redesign its rural customer survey, it looks forward to any results flowing from this exercise should NLH proceed in the absence of a direction from the Board.

The Board also acknowledges the parties' request that the Board prepare or obtain a report on PBR alternatives for NLH and NP. The Board notes the parties' agreement and will consider the request as part of its ongoing regulatory mandate for both utilities.

XI. HEARING COSTS

Both the IC and the Towns of Labrador City and Wabush requested the Board award costs in their favour respecting their appearance at the hearing. Section 90(1) of the *Act,* states:

> *"90 (1) The costs of and incidental to a proceeding before the Board shall be in the discretion of the Board, and may be fixed at a definite amount, or may be taxed and the board may order by whom they are to be taxed and to whom they are to be allowed and the board may prescribe a scale under which costs shall be taxed."*

In support of its request for costs the IC referred the Board to the Supreme Court of Canada's 1986 decision in *Bell Canada v. Consumer's Association of Canada et al., [1986] 1 S.C.R. 190 (S.C.C.)* in which, the IC argued, the principle was established that costs will be available to intervenors who have participated in a responsible way and contributed to a tribunal's better understanding of the issues before it.

The IC also submitted that the Board's jurisdiction and discretion with respect to an award of costs is also supported by the decision of the Supreme Court of Newfoundland and Labrador, Court of Appeal in *Newfoundland and Labrador Hydro v. Newfoundland and Labrador Federation of Municipalities*(1979), 24 Nfld. & P.E.I.R. 317. In this case NLH challenged the Board's award of costs partly on the ground that the cost amount was excessive and partly on the ground that the costs should have been taxed on a party and party basis. The Court of Appeal ultimately found that the Board had the jurisdiction and discretion to make the cost award in question.

The Towns of Labrador City and Wabush submitted that the regulatory rate process is a complicated and expensive one requiring the input of people with specialized expertise. They argued that the process has credibility only if the affected parties are able to participate and present the necessary evidence.

NLH submitted that, until its 2001 general rate application and hearing, the Board had not awarded costs to intervenors such as the IC. At that time the Board fixed an amount for costs for the IC and stated that its decision was *"solely to recognize the circumstances surrounding this application"* and was not intended to set a precedent. [Order No. P. U. 7(2002-2003), pg.164] NLH submitted the IC have adequate financial resources to cover their own costs and that costs should not be awarded in their favour in this proceeding. NLH did not take a specific position on the matter of awarding costs to the Towns of Labrador City and Wabush.

NLH further requested, should the Board determine it is appropriate that costs be paid to the IC and the Towns of Labrador City and Wabush, an estimate of these costs should be included with the costs of the Board and the CA and amortized over a three year period to be recovered in rates.

The issues before the Board at this hearing include the appropriateness of NLH's forecast costs, the appropriate allocation of those costs, rate of return, capital structure, COS issues, and the resulting rates on the Island and in Labrador. Informed participation of the parties in these complex matters facilitates the proper discharge of the Board's obligation to ensure that the power policy of the Province is adhered to and that consumers are supplied power at the lowest possible cost consistent with reliable service.

The Board acknowledges that the proposed rate increases for the IC and the Towns are significant. In addition the proposals result in a fundamental change to the historic rate structure in Labrador West and Labrador East. The Board concludes that, in light of the significant impacts of the Application proposals on both the IC and the Towns, the full participation of both in this Application was important. Both the IC and the Towns participated in a responsible manner and have contributed to the Board's understanding of the issues through the calling and cross-examination of witnesses, and the tendering of written and oral argument. The Board concludes that an award of costs to both the IC and the Towns of Labrador City and Wabush is fair and appropriate in the circumstances.

The IC asked the Board to award taxed costs on a party and party basis. The Towns asked for their costs in relation to the intervention without specific reference to taxation. As set out above, Section 90 of the *Act* allows the Board to fix costs at a definite amount or to order that costs be taxed with the Board having discretion to prescribe a scale under which they are taxed. The Board has not prescribed a scale under which costs should be taxed and generally fixes an amount of costs rather than ordering taxation. This approach acknowledges the discretion of the Board as well as its expertise with respect to its proceedings which are by their nature technical and unique. The Board confirms that, in the absence of a scale under which costs in relation to hearings before the Board can be taxed, the Board is in the best position to exercise discretion as to the appropriate amount of costs. The Board will therefore require both the IC and the Towns to submit a detailed statement of their costs with supporting material for the consideration of the Board in the exercise of its discretion to fix an amount of costs.

The Board will make an award of costs to the IC and the Towns of Labrador City and Wabush. The Board will require the IC and the Towns of Labrador City and Wabush to file detailed statements of costs with the Board no later than May 28, 2004.

PART THREE. SUMMARY OF BOARD DECISIONS

I. CAPITAL STRUCTURE

Government Guarantee

1. The Board accepts that the Government guarantee plays a key role in supporting Newfoundland and Labrador Hydro's (NLH) ability to maintain a sound credit rating in the financial markets of the world and to access needed capital at reasonable rates.

Dividend/Capital Structure

2. The Board finds that a dividend policy of 25% of annual net income is most supportive of NLH's stated objective of moving toward a capital structure of 80/20 within a reasonable time frame. For purposes of determining the 2004 test year revenue requirement, NLH will be ordered to adjust the forecast dividend payment in 2004 to 25% of net income from the proposed 75% payout, incorporating the impact of this adjustment on the forecast return on equity and interest expense.

NLH as an Investor Owned Utility

3. The Board finds insufficient justification at this time to warrant treatment of NLH comparable to an investor owned utility for purposes of setting its financial targets. The onus is on NLH in future applications to clearly demonstrate through its operations and financial plans how it will achieve financial targets similar to an investor owned utility and what impacts this will have on its customers. The Board will continue to recognize NLH as a Crown owned utility afforded the benefit of a debt guarantee provided by its shareholder, Government, which sustains NLH's access to the capital markets.

Return on Equity

4. The Board concludes that an appropriate return on equity for NLH for the purposes of determining the weighted average cost of capital for the 2004 test year is 5.83%.

II. FOREASTING: PRODUCTION AND FUEL COSTS

Test Year Hydraulic Production

5. The Board accepts NLH's proposal to use the 30-year average for the estimation of hydraulic production for the 2004 test year, which will result in a total forecast hydraulic production of 4,582.15 GWh.

6. The Board will direct NLH to file its next general rate application using the full historic hydraulic data flow record with evidence demonstrating how the following outstanding issues have been addressed:
   i. correction of the internal inconsistencies in the data series; and
   ii. selection of an appropriate computer model for simulation.

Test Year Thermal Production

7. The Board accepts the 2004 test year forecast of thermal production of 1,780.61 GWh.

Holyrood No. 6 Fuel Conversion

8. The Board finds that a conversion factor for No. 6 fuel at Holyrood of 630 kWh/bbl is appropriate for the 2004 test year. This conversion factor will also be used in the Rate Stabilization Plan.

Fuel Price Forecasting

9. The Board accepts the 2004 test year forecasts for fuel prices as proposed by NLH in its October 31, 2003 revised filing for determining the 2004 test year fuel costs.

III. REVENUE REQUIREMENT

Depreciation

10. The Board accepts NLH's 2004 test year depreciation expense for the purposes of determining the 2004 test year revenue requirement subject to any adjustments arising from this Decision and Order, including:
    i. a reduction of 5.0% in the approved 2004 capital budget; and
    ii. an adjustment to the forecast 2004 capital retirements to 0.39% of its total capital assets.

Fuel Costs

11. The Board accepts NLH's current fuel purchasing policies and practices.

No. 6 Fuel

12. The Board will direct NLH to reflect a fuel conversion factor of 630 kWh/bbl for No. 6 fuel at Holyrood in its 2004 test year fuel costs.

Diesel Fuel

13. The Board accepts NLH's 2004 test year diesel fuel cost of $6,801,000.

Other Fuels

14. The Board accepts NLH's 2004 test year costs for other fuels of $757,000.

Purchased Power

15. The Board accepts NLH's 2004 test year purchased power expense of $33,594,000.

Salaries and Fringe Benefits

16. The Board will direct NLH to reduce its 2004 test year salary expense by $500,000 to reflect a higher vacancy allowance.

System Equipment Maintenance

17. The Board will require NLH's 10-year plan of maintenance expenditures for the Holyrood Generating Station to be updated annually to reflect changing operating circumstances.

18. The Board accepts NLH's 2004 test year system equipment maintenance expense of $17,440,000.

Transportation

19. The Board will direct NLH to reduce its 2004 test year transportation expense by $185,000.

Miscellaneous Expenses

20. The Board accepts NLH’s 2004 test year miscellaneous expense of $4,185,000.

Other Cost Categories

21. The Board accepts NLH’s 2004 test year expenses for travel, office supplies, insurance, equipment rentals and building rentals and maintenance, totalling $8,977,000.

22. The Board will allow an increase in the 2004 test year professional services expense of $200,000 to reflect the amortization over a three year period of additional regulatory costs.

Loss on Disposal of Capital Assets

23. The Board accepts NLH’s 2004 test year expense of $1,266,000 for loss on disposal of capital assets.

Capitalized Expenses

24. The Board will direct NLH to increase its 2004 test year capitalized expense by $2,000,000.

Non-Regulated Operations and Inter-Company Charges

25. The Board accepts NLH’s treatment of non-regulated expenses and inter-company charges in determining its 2004 test year revenue requirement.

26. The Board will direct NLH to file a report on the appropriateness of discontinuing the use of regulated equity in favour of book equity as part of its next general rate application.

Interest Expense

27. The Board accepts NLH’s 2004 test year interest expense, subject to any adjustments arising from this Decision and Order.

Productivity Allowance

28. The Board will not impose a productivity allowance for NLH’s 2004 test year revenue requirement in light of other decisions taken in this Decision and Order.

IV. RATE STABILIZATION PLAN

29. The Board will direct NLH to complete a review of the operation of the Rate Stabilization Plan for the period January 1, 2004 to December 31, 2005. A report on this review setting out an assessment of the impact on customers should be filed with the Board no later than June 30, 2006.

V. RATE BASE

Fixing and Determining Rate Base

30. The Board will fix and determine the 2002 rate base at $1,356,207,000.

31. The Board will require NLH to submit, as part of its next general rate application, a report with respect to the review of its property and assets setting out the acquisition date, the original cost, the purpose of the asset, the net book value and, where applicable, the load served.

Forecast Average Rate Base and Return on Rate Base

32 The Board will require NLH to file a revised calculation of rate base and rate of return on rate base for the 2004 test year which reflects the findings of the Board in this Decision and Order.

Range of Return on Rate Base and Excess Earnings Account

33. As part of its revised filing of rate base and rate of return on rate base NLH will be required to file for the Board's consideration a proposal for a range of return on rate base and a definition of an *"excess earnings"* account. This proposal should include an analysis of several alternate ranges along with the associated impacts.

Automatic Adjustment Formula

34. The Board will not implement an automatic adjustment mechanism for NLH's rates at this time. NLH will be required to submit a report containing a proposal for such a mechanism with analysis as to the impacts for consideration at its next general rate application.

VI. COST OF SERVICE

35. The Board accepts the proposed changes to the Cost of Service methodology with respect to the assignment of Hydro Place costs, NLH's municipal taxes and Board assessments, and with respect to the functionalization of general plant assets.

GNP Generation Assets

36. The Board accepts NLH's proposed assignment of the generation assets on the Great Northern Peninsula as common plant.

GNP Transmission Assets

37. The Board accepts NLH's proposed assignment of transmission assets on the Great Northern Peninsula to Hydro Rural.

Doyles-Port aux Basques Transmission Assets

38. The Board accepts NLH's proposed assignment of transmission assets on the Doyles-Port aux Basques system as specifically assigned to Newfoundland Power Inc. (NP).

Burin Peninsula Transmission Assets

39. The Board does not accept NLH's proposal to assign all costs associated with the Burin Peninsula transmission assets as common. The Board will direct NLH to separate costs for TL219 and TL212. Costs associated with TL219 will be specifically assigned to NP and costs associated with TL212 will be assigned common.

Treatment of NP Generation

40. The Board accepts NLH's treatment of NP's hydraulic and thermal generation in the Cost of Service study.

41. The Board will direct NLH to commission an independent study, to be filed with its next general rate application, of the treatment of NP's generation. This study should assess the value of NP's generation to the system and make recommendations on how the generation should be accounted for, both operationally and financially, in the Cost of Service study and rate design. NLH will be permitted to recover its reasonable costs associated with this study and may accumulate these costs in a deferral account to be dealt with at its next general rate application.

NP Demand Forecasts

42. The Board accepts the demand and energy forecasts for NP as proposed by NLH for use in the 2004 test year Cost of Service study.

VII. LABRADOR INTERCONNECTED SYSTEM

43. The Board finds that NLH's proposals for uniform rates for the Labrador Interconnected System are not unjustly discriminatory and rejects the complaint of the Towns of Labrador City and Wabush.

44. The Board accepts NLH's proposed five year plan to implement uniform rates for Labrador Interconnected customers as set out in its Application. The Board will direct NLH to file for approval a revised Schedule of Rates for each proposed rate change set out in the five year plan.

45. The Board accepts the proposal that NLH will adjust the Rural Rate Alteration Component of the Rate Stabilization Plan based on its projection of the five year phase-in of Labrador rates and the revenue credit available from secondary energy sales to CFB Goose Bay with the provision that it be applied only to the portion of the revenue credit applicable to NP and that the rates of the Labrador Interconnected customers not be negatively affected by this adjustment.

VIII. RURAL SYSTEMS

Rural Deficit

46. The Board will require NLH to submit, in conjunction with its annual financial report, an annual report on the rural deficit which should include the following:
    i. the total rural deficit and a breakdown of its components by system (Island Interconnected Rural, Island and Labrador Isolated Rural, and L'Anse au Loup);
    ii. a five year forecast of the rural deficit by system;
    iii. the number of communities and customers served in each system;
    iv. the cost per kWh per system, showing a comparison with cost per kWh for the Island Interconnected System (less rural) and the Labrador Interconnected System;
    v. the deficit per customer and the cost recovery ratios for each system; and
    vi. a summary of any specific initiatives undertaken to reduce the capital or operating costs in each system.

Lifeline Block for Rural Isolated Domestic Customers

47. The Board will direct the implementation a Seasonal Lifeline Block for NLH's Rural Isolated Domestic customers, both Island and Labrador, as set out below:

Seasonal Lifeline Block for NLH Diesel Systems		
Month	**Existing Lifeline (kWh)**	**Alternative Seasonal Lifeline Including Hot Water (kWh)**
January	700	1,000
February	700	1,000
March	700	900
April	700	900
May	700	800
June	700	800
July	700	700
August	700	700
September	700	700
October	700	800
November	700	900
December	700	1,000
Total kWh	**8,400**	**10,200**
Monthly Average kWh	**700**	**850**

48. Rural Isolated Domestic customers will continue to pay the same rate as NP's domestic customers for consumption within the Seasonal Lifeline Block. The existing block structure for these customers for energy consumption above the Seasonal Lifeline Block will be maintained. The existing policy of automatically adjusting the rates for consumption above the lifeline block by the average rate change approved by the Board for NP will continue to apply.

Preferential Rates

49. The Board accepts NLH's proposals for preferential rates for certain customers on the Island Interconnected and Isolated Systems as being in accordance with Government directives.

Rates for Isolated General Service Customers

50. The Board will approve NLH's proposal for the phase-in of a demand-energy rate structure, including the consolidation of rate classes and the elimination of the lifeline block, for general service customers on the isolated diesel systems over a three year period. The Board will direct NLH to file for approval a revised Schedule of Rates for each proposed rate change set out in the three year plan. Rates for these customers will continue to be adjusted by the average rate of change granted to NP in any general rate application.

Energy Tax Proposal

51. The Board will not recommend taxing legislation with respect to the recovery of the rural deficit, as proposed by the Towns of Labrador City and Wabush.

IX. RATES ISSUES/RATE DESIGN

Wholesale Demand-Energy Rate for NP

52. The Board finds that the introduction of a demand-energy rate by NLH for NP's purchased power is appropriate.

53. The Board will require NLH to file, no later than July 31, 2004, using the embedded Cost of Service for the 2004 test year adjusted for this Decision and Order, an application for the demand-energy rate to be implemented for NP on January 1, 2005. The application and supporting documents will fully address, among other things:

    i. The degree of risk to be assumed by NLH;
    ii. The expected relationship between the risk assumed by NLH and the response in terms of conservation efforts by NP;
    i. An appropriate weather normalization mechanism, with quantification of the intrinsic error in the formula;
    ii. The treatment of NP's generation as has been determined by this Decision and Order;
    iii. Appropriate costing and billing determinants;
    iv. The use of adequate metering, or, in its absence at any supply points, an appropriate estimation formula;
    v. The effects of variations in NP's hydraulic generation and native load, individually and together; and
    vi. The effects of varying levels of demand and energy rates for a range of usage patterns.

In the meantime, NLH will continue to charge NP an energy-only rate as proposed in its Application, revised to reflect the findings of the Board in this Decision and Order.

Interruptible *"B"* Contract for Abitibi Consolidated Company of Canada-Stephenville

54. The Board will not order NLH to reinstate the Interruptible B rate for Atibiti Consolidated Company of Canada-Stephenville or to make a similar rate available to the Industrial Customers.

Rules and Regulations for Service

55. The Board accepts NLH's proposed changes to the Rules and Regulations for Rural Customers.

Rate Change/Implementation

56. In order to finalize rates to be implemented as a result of this Decision and Order, NLH will be required to incorporate the decisions of the Board by:
    i. adjusting its revenue requirement and calculation of rate base and rate of return on rate base;
    ii. revising its October 31, 2003 Cost of Service study for the 2004 test year;
    iii. revising its proposed Schedule of Rates for the various customer classes based on the updated Cost of Service; and
    iv. addressing the consumption on which the rates will be effective for the bills of NP, the Industrial Customers, Labrador Interconnected firm customers, Island Interconnected Rural Customers and Isolated Rural Customers;

    and filing the above with the Board for approval.

X. OTHER ISSUES

Regulatory Oversight – Planning, Performance Measures and Reporting

57. The Board will require NLH to incorporate the following Key Performance Indicators (KPIs) into its annual reporting to the Board, commencing with its 2004 annual report.
    i. Thermal conversion factor (MWh generated at Holyrood per barrel of oil-MWh/bbl);
    ii. Hydraulic conversion factor (MWh generated per million cubic meters of water – MWh/MCM);
    iii. Corporate operating, maintenance and administration expense (OM&A) per MWh generated;
    iv. Generation OM&A per MWh generated;
    v. Generation OM&A per MW installed capacity;
    vi. Transmission OM&A per km of transmission line; and
    vii. Distribution OM&A per km of distribution line.

58. The Board will direct NLH to propose to the Board for approval a *"peer group"* of utilities for the purposes of external benchmarking of its KPIs.

59. The Board will direct NLH to file by December 31, 2004 a report outlining:
    i. a comprehensive description of NLH's strategic and business planning processes;
    ii. a description of how corporate goals and strategies are communicated and operationalized, including how specific operational targets are identified and linked to corporate goals and strategies; and
    iii. a description of how management performance and employee incentives are tied to achieving targeted goals, outcomes and efficiencies.

60. The Board will direct NLH to file annually, commencing with its 2004 annual financial report, a report outlining:
    i. a strategic overview highlighting core strategies, corporate goals and achievements;
    ii. appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes/measures, including the KPIs as set out above; and
    iii. initiatives targeting productivity or efficiency improvements, including status of ongoing projects and improved performance resulting from completed projects.

Marginal Cost Study

61. The Board will direct NLH to undertake and file with the Board no later than June 30, 2006 a marginal cost study. NLH will be permitted to recover its reasonable costs associated with this study and may accumulate these costs in a deferral account to be dealt with at its next general rate application.

Future Supply/Integrated Resource Planning

62. The Board has authority and responsibility to ensure that adequate planning occurs for the production, transmission and distribution of least cost reliable power in the Province. While the Board will make no order at this time with respect to Integrated Resource Planning, the utilities may be required by the Board, consistent with its mandate, to participate in a generic process to address issues and benefits associated with Integrated Resource Planning.

Demand Side Management/Conservation

63. The Board encourages NLH to continue to raise consumer awareness and develop/implement programs aimed at energy efficiency and conservation. The Board will not direct NLH at this time respecting demand side management initiatives but will consider the manner and timing of a generic proceeding which will address demand side management options and impacts on the overall system.

XI. HEARING COSTS

64. The Board will make an award of costs to the Industrial Customers and the Towns of Labrador City and Wabush. The Board will require the Industrial Customers and the Towns of Labrador City and Wabush to file detailed statements of costs with the Board no later than May 28, 2004.

PART FOUR. THE ORDER

IT IS THEREFORE ORDERED THAT:

REVISED REVENUE REQUIREMENT AND COST OF SERVICE

1. **NLH shall file a revised total revenue requirement and cost of service study for the 2004 test year based on its October 31, 2003 filing, incorporating the determinations of the Board in this Decision and Order, including:**
   - i. **The forecast dividend payout shall be reduced for rate setting purposes to 25% of net income;**
   - ii. **The allowed rate of return on equity for the purposes of determining the weighted average cost of capital shall be 5.83%;**
   - iii. **The fuel conversion factor for No. 6 fuel at Holyrood shall be 630 kWh/bbl;**
   - iv. **The approved 2004 Capital Budget shall be adjusted for rate setting purposes to reflect a reduction of 5.0%;**
   - v. **The forecast 2004 capital retirements shall be increased to 0.39% of total capital assets;**
   - vi. **Salary expenses shall be reduced by $500,000;**
   - vii. **Transportation expense shall be reduced by $185,000;**
   - viii. **Professional services expense shall be increased by $200,000;**
   - ix. **Capitalized expenses shall be increased by $2,000,000; and**
   - x. **Costs associated with TL219 shall be specifically assigned to NP and costs associated with TL212 shall be assigned common.**

RATE BASE AND RETURN ON RATE BASE

2. **NLH shall file for the approval of the Board a revised calculation of rate base and rate of return on rate base for the 2004 test year based on the approach and methodology proposed in its Application, incorporating the determinations of the Board in this Decision and Order.**

3. **As part of its revised filing of rate base and rate of return on rate base NLH shall file for the approval of the Board:**
   - i. **a proposal for a range of return on rate base including an analysis of several alternate ranges with impacts; and**
   - ii. **a definition of an "excess earnings" account to be included in the company's system of accounts to which earnings above the maximum of the allowed range of rate of return on rate base will be credited.**

4. **The rate base for the year ending December 31, 2002 is hereby fixed and determined at $1,356,207,000.**

RATES, RULES AND REGULATIONS

5. **NLH shall file for the approval of the Board a revised Schedule of Rates, Rules and Regulations to be effective as of July 1, 2004, addressing the consumption on which the rates will be effective, and incorporating the determinations of the Board in this Decision and Order, including:**
   i. **Rates charged to NP shall be on an energy-only basis.**
   ii. **Rates charged to Rural Isolated Domestic customers for consumption of electricity:**
      (a) within the Seasonal Lifeline Block, as accepted by the Board in this Decision and Order, shall be the same rates charged to NP's domestic customers; and
      (b) above the Seasonal Lifeline Block shall continue as historically structured and determined.
   iii. **The Rules shall include a statement of the policies for automatic changes in rates for all of NLH's rural customers whose rates and rate changes are tied to NP's rates and rate changes as and when approved by the Board.**

6. **NLH shall file for the approval of the Board a revised Schedule of Rates no later than November 30 for each subsequent year for rate changes proposed in accordance with:**
   i. **The five-year implementation of uniform rates on the Labrador Interconnected System; and**
   ii. **The three-year phase-in of a demand-energy rate structure for Rural Isolated General Service customers.**

7. **The Complaint of the Towns of Labrador City and Wabush is dismissed.**

8. **The adjustment of the rural rate alteration component of the RSP based on the phase-in of Labrador rates and the revenue credit from secondary energy sales to CFB Goose Bay shall be applied only to the portion of the revenue credit applicable to NP and shall not negatively affect the rates of the Labrador Interconnected customers.**

9. **NLH shall file no later than July 31, 2004, based on the revised cost of service study for the 2004 test year, an application with supporting documentation as set out in this Decision and Order for a demand-energy rate to be implemented for NP as of January 1, 2005.**

REPORTING

10. **NLH shall file as part of its next general rate application;**
   i. **a report on the discontinuance of the use of regulated equity in favour of book equity;**
   ii. **a report with respect to the review of its property and assets;**
   iii. **a report setting out a proposal for an automatic adjustment mechanism with analysis as to impacts; and**

- **iv. an independent study of the treatment of NP's generation assessing the value of NP's generation to the system, with recommendations on how this generation should be accounted for in the cost of service study and rate design.**

11. NLH shall file with the Board on or before June 30, 2006:
- **i. a report on the operation of the Rate Stabilization Plan for the period January 1, 2004 to December 31, 2005; and**
- **ii. a system-wide marginal cost study.**

12. NLH shall file a ten year plan of maintenance expenditures for the Holyrood generating station with its annual capital budget application, until otherwise directed by the Board.

13. NLH shall file with its annual financial report, commencing in 2004 until otherwise directed by the Board, an annual report on the rural deficit addressing the following:
- **i. the total rural deficit and a breakdown of its components by system (Island Interconnected Rural, Island and Labrador Isolated Rural, and L'Anse au Loup);**
- **ii. a five year forecast of the rural deficit by system;**
- **iii. the number of communities and customers served in each system;**
- **iv. the cost per kWh per system, showing a comparison with cost per kWh for the Island Interconnected System (less rural) and the Labrador Interconnected System;**
- **v. the deficit per customer and the cost recovery ratios for each system; and**
- **vi. a summary of any specific initiatives undertaken to reduce the capital or operating costs in each system.**

14. NLH shall file a report no later than December 31, 2004 proposing a *"peer group"* of utilities for the purposes of external benchmarking of its KPIs.

15. NLH shall file no later than December 31, 2004 a report outlining:
- **i. A comprehensive description of NLH's strategic and business planning processes;**
- **ii. A description of how corporate goals and strategies are communicated and operationalized including how specific operational targets are identified and linked to corporate goals and strategies; and**
- **iii. A description of how management performance and employee incentives are tied to achieving targeted goals, outcomes and efficiencies.**

16. NLH shall file with its annual financial report, commencing in 2004 until otherwise directed by the Board, an annual report outlining:
- **i. A strategic overview highlighting core strategies, corporate goals and achievements;**
- **ii. Appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes/measures including the additional KPIs accepted in this Decision and Order; and**

iii. Initiatives targeting productivity or efficiency improvements, including status of ongoing projects and improved performance resulting from completed projects.

<u>OTHER ISSUES</u>

17. **NLH shall file its next general rate application using the full historic hydraulic data flow record with evidence as to how the following issues have been addressed;**
    i. Correction of the internal inconsistencies in the data series; and
    ii. Selection of an appropriate computer model for simulation.

18. **NLH may accumulate the costs associated with the marginal cost study and the independent study of the treatment of NP generation in a deferral account to be addressed at NLH's next general rate application.**

<u>HEARING COSTS</u>

19. **NLH shall pay the expenses of the Board arising from this Application, including the expenses of the Consumer Advocate incurred by the Board, pursuant to Section 117 of the *Act*.**

20. **The Industrial Customers shall submit a detailed statement of costs no later than May 28, 2004 for the consideration of the Board in making an award of costs to the Industrial Customers.**

21. **The Towns of Labrador City and Wabush shall submit a detailed statement of costs no later than May 28, 2004 for the consideration of the Board in making an award of costs to the Towns.**

Dated at St. John's, Newfoundland and Labrador this 4th day of May 2004.

Robert Noseworthy,
Chair & Chief Executive Officer.

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

G. Fred Saunders,
Commissioner.

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G. Cheryl Blundon,
Board Secretary.

Newfoundland & Labrador
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
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Decision **2000-6**

NOVA Gas Transmission Ltd.

1999 Products and Pricing

Alberta Energy and Utilities Board

CONTENTS

ALBERTA ENERGY AND UTILITIES BOARD
Calgary, Alberta

	Decision 2000-6
NOVA GAS TRANSMISSION LTD.	**Application 990157**
1999 PRODUCTS AND PRICING	**File 1604-3**

SUMMARY OF FINDINGS AND DIRECTIONS

In its consideration of Application 990157, the Alberta Energy and Utilities Board (the Board/ EUB) has reached the following conclusions and decisions:

1) The Board concludes that an industry-wide consensus was not reached beyond a bilateral agreement between NOVA Gas Transmission Ltd. (NGTL) and Canadian Association of Petroleum Producers (CAPP).

2) The Board is not prepared to accept the application as a package but rather has examined and has decided upon its individual elements.

3) The Board finds that the NGTL proposal for Receipt Point Specific Rates best meets accepted rate making principles, is in the public interest, and is therefore approved. The Board directs NGTL to incorporate Receipt Point Specific Rates and to apply the floor price and ceiling as described in the application over a four-year Transition Period.

4) The Board accepts NGTL's request to eliminate the commodity charge.

5) The Board directs NGTL to maintain the current cost allocation between intra-Alberta and ex-Alberta services.

6) The Board denies the New Services proposal.

7) The Board approves the new facility construction proposal as filed but is not prepared to allow NGTL affiliates to participate in the construction of lateral facilities until a Code of Conduct satisfactory to the Board is in place.

8) The Board accepts that new Alberta receipt laterals and new Alberta delivery laterals will be included in the rate base, provided such facilities can be in service within the first four months following implementation of this decision. Thereafter, such facilities shall be excluded from NGTL's rate base and from its revenue requirement.

9) The Board approves in principle the concept of term-differentiated rates. The Board also approves the applied-for term/rate relationship over the Initial Period[1].

10) The Board directs that the rate for interruptible receipt service be changed from the current 110 per cent to 115 per cent of the firm service receipt point specific price for a three-year firm receipt contract.

11) The Board approves the applied-for renaming of existing services, including changing the intra-Alberta service to a firm service.

12) The Board accepts in principle the proposed revenue collar, including the revenue-sharing concept described in the application. The Board also accepts the applied-for annual revenue collar of plus or minus $5 million to be applicable for the Initial Period.

13) The Board directs that notice of renewal for firm service shall increase from the current six months to twelve months. The Board directs that a shipper that has excess of twelve months remaining in an existing firm service contract shall have the right to renew the service by giving NGTL not less than twelve months' notice prior to the expiry date of the contract if such service expires on or after March 1, 2001.

14) The Board denies the proposed 24-month renewal incentive notice.

15) The Board directs the implementation of receipt transfers and term swaps as proposed by NGTL.

16) The Board denies the proposed administrative fee.

17) The Board directs that the commencement or implementation date of its approvals shall occur on the first day of the month occurring eight weeks following issuance of this decision.

18) NGTL shall incorporate the Board's findings in its tariff and terms and conditions of service and shall file these revised tariffs and terms and conditions of service with the Board 21 days following the release of this decision.

[1] Initial Period as defined by NGTL means 24 months following the Commencement Date stipulated as the first day of the month occurring 56 days following approval of the application.

1 INTRODUCTION

By letter dated April 6, 1999, NOVA Gas Transmission Ltd. (NGTL) filed an application with the Alberta Energy and Utilities Board (the Board/EUB) for approval of new service offerings and related rates, tolls, and charges. The application contemplated a fundamental change from NGTL's current postage stamp rate design and from the terms and conditions for providing natural gas transportation service within Alberta.

1.1 Background and History of NGTL's Rate Design

In 1954, through the passage of The Alberta Gas Trunk Line Company Act, the corporate entity that became NGTL was established. The objective of The Alberta Gas Trunk Line Company Act was to ensure that the pipeline to be built to export natural gas from the province would be Alberta owned and operated. NGTL's rate design at the time was based on the dedicated plant method. This meant that specific units of plant or percentages of common plant were dedicated to individual shippers under cost of service agreements for the recovery of the corresponding owning and operating costs. A customer requesting new facilities would bear the cost of those facilities. Increasing numbers of customers, backhauls, and gas exchanges eventually rendered the allocation of part of plant to specific customers an arbitrary and complex process.

In 1978, following a public inquiry in which several rate design alternatives were examined, the Public Utilities Board (PUB), one of the predecessor boards of the EUB, recommended postage stamp rates for natural gas transported on the NGTL system but destined to markets outside Alberta. The provincial government accepted and implemented this recommendation through regulation in 1980. The PUB recommended that NGTL's costs be "rolled in" and recovered through a commodity-based postage stamp toll. The PUB determined that all customers transporting natural gas to border delivery points would pay the same rate regardless of the distance natural gas travelled within Alberta.

For natural gas consumed in the province, the intra-Alberta rate design continued to identify specific receipt and delivery points. Given the few customers and contracts involved, natural gas balancing between specific receipt and delivery points was possible.

With deregulation of natural gas commodity pricing in 1986, NGTL redesigned its rates to institute separate demand and commodity components for ex-Alberta deliveries. The rate for ex-Alberta firm service was changed, effective November 1, 1986, from a commodity postage stamp to a two-part demand/commodity postage stamp rate design. The objective of this change was to increase cost accountability. Under this rate design, the fixed-cost portion of the revenue requirement was recovered through a demand charge based on total contracted volumes at receipt and delivery points, while the variable costs were recovered through a commodity charge based on forecast volumes.

On November 1, 1989, after consultation with interested parties, NGTL implemented a demand/commodity postage stamp rate design for intra-Alberta deliveries. However, in this case only receipt charges were applicable for intra-Alberta volumes and delivery charges were arbitrarily set at zero. The net effect was that the intra-Alberta postage stamp rate was half of the postage stamp rate applicable for natural gas leaving the province. NGTL considered that this properly reflected the fact that, as demonstrated by the company's annual distance of haul study, on average natural gas destined for intra-Alberta markets travels approximately half the distance as that of natural gas destined markets outside Alberta.

In Phase II of NGTL's 1995 General Rate Application (GRA), the Board examined the continued appropriateness of the postage stamp rate design. At the time, PanCanadian Petroleum Limited (PanCanadian) proposed, as an alternative to postage stamp rates, a distance-based toll design. In *Decision U96055*, the Board noted that in accepting the continuation of the postage stamp rate design, some elements of fairness and economic efficiency might have been exchanged for simplicity and other benefits. However, in reaffirming the postage stamp rate design, the Board stated that it also had regard for the fact that the relative value of such benefits had manifested themselves during the hearing in the wide acceptance expressed by participants for the postage stamp rate design.

During the same hearing, the issue of whether postage stamp tolling design would encourage by-pass of the NGTL system by shippers with natural gas supplies close to the border delivery points was examined. The Board determined that while this was a real issue, bypass matters should be dealt with on a case-by-case basis.

Since *Decision U96055*, the Board has considered and approved two Load Retention Service offerings by NGTL in order to allow the company to avoid commercially viable but economically inefficient bypass. The first, referred to as LRS, was approved as per the Board's *Decision U97096*. LRS was offered to a limited number of shippers that had signed precedent agreements for firm transportation of 732.3 million cubic feet per day (MMcf/d) with the proposed Palliser Pipeline (Palliser). Palliser would have bypassed certain portions of NGTL's system in the southeast part of the province. The second load retention service, LRS-2, was approved as per Order U99042. LRS-2 was a competitive service offering by NGTL negotiated in order to retain Northstar Energy Corporation (Northstar) as a customer in the Coleman area in southwestern Alberta.

In *Decision U97096*, the Board acknowledged that there were initiatives under way involving NGTL and its customers to address the ongoing appropriateness of NGTL's long-standing postage stamp rates and to examine alternative rate designs. The Board stated that NGTL should address alternatives to load retention rates in a full and meaningful way prior to requesting future load retention services.

1.2 The Application

NGTL submitted that its consultation with industry associations and other stakeholders on new service offerings commenced in late 1996 and continued until March 1999. In its evidence, NGTL discussed eight distinct phases of discussions and negotiations, which it referred to collectively as the Industry Process. It stated that the purpose of the Industry Process was to develop a new service and rate design framework consistent with the concerns of both NGTL and its many customers.

NGTL submitted that the early stages of the Industry Process were broad based but unsuccessful in reaching an industry-wide settlement. NGTL stated that it then entered into direct negotiations with the Canadian Association of Petroleum Producers (CAPP) and the Small Explorers and Producers Association of Canada (SEPAC). As a result of the discussions, NGTL signed a memorandum of understanding (MOU, the Agreement) with CAPP on March 16, 1999. SEPAC, however, did not sign the MOU. NGTL submitted that during its negotiations with the two industry associations, it also held numerous bilateral discussions with other stakeholders seeking their input and providing opportunities to express their concerns. NGTL stated that ultimately the application was the result of this consultation process.

NGTL submitted that the application was consistent with the MOU and requested that the Board either approve or reject the application as filed. NGTL noted that the application should be viewed as a package, since it reflected a number of compromises reached between NGTL and CAPP. If the Board could not approve the entire application as filed, NGTL submitted that the current postage stamp rate should remain in place until such time as it had had an opportunity to pursue other alternatives.

NGTL noted that while the application might not reflect all of the diverse interests of its stakeholders, it had expended significant efforts to accommodate the wide-ranging concerns of all parties. NGTL further submitted that although some differences between the parties remained, there was a broad consensus that a fundamental change in its rate design was warranted. It added that a key objective of the MOU and the consultation with stakeholders was to ensure increased cost accountability while maintaining simplicity, flexibility, and market liquidity. At the same time, the proposal would also provide NGTL with appropriate tools to successfully compete in light of the emergence of pipe-to-pipe competition.

NGTL observed that the proposed rate design and the terms and conditions of service would constitute a significant change from the postage stamp rate design. Approval of the application would result in changes in the way revenue requirement is determined and would also have implications for the provision of new facilities. According to NGTL, key components of the proposal were that:

- Receipt charges would now reflect costs attributable to the relative diameter of pipe and the distance from each receipt point to the major export delivery points.

- Receipt and delivery contracts would remain separate. Consequently, market transparency and liquidity as currently afforded through the NOVA Inventory Transfer (NIT) would be preserved.

- Following a short transition period, the construction of receipt and delivery laterals would no longer be part of NGTL’s regulated business.

- The method of determining intra-Alberta and ex-Alberta delivery charges would remain unchanged.

- NGTL would be able to develop new services, incremental to existing services, outside the revenue requirement with full cost and benefit to the account of NGTL shareholders.

- Term-differentiated tolls would be introduced in order to offer customers a choice of prices and terms.

- A new pricing structure with a price floor and ceiling would be phased in over four years in order to provide customers the opportunity to adapt to the changes.

- The renewal provisions for transportation services, along with receipt transfers and swap restrictions, would be amended to provide greater cost accountability.

1.3 The Interventions

Several of the interveners did not agree that the Industry Process was as inclusive as NGTL had described. Nor did they believe that their concerns were either addressed or accounted for in a meaningful manner. They expressed different views from those of NGTL on whether consensus had been reached regarding the objectives and principles upon which NGTL claimed to have based its application. Many believed that the bilateral discussions that took place during the period that NGTL was negotiating the MOU with CAPP and SEPAC were considered by NGTL to be only for information purposes.

The interveners took a wide range of positions regarding disposition of the application. The Western Export Group (WEG),[2] representing several export customers, was the only intervener that recommended approval of the application as filed. Others, including CAPP, Imperial Oil Resources Limited (Imperial), Clan Duncan Resources Limited (Clan Duncan), PanAlberta Gas (PanAlberta), PanCanadian, Shell Canada (Shell) and Suncor Energy Inc. (Suncor) recommended that the application be approved subject to having a satisfactory Code of Conduct governing NGTL's business practices in place prior to implementation. Such a Code of Conduct would be designed to ensure that no competitive advantage was given to nonregulated NGTL affiliates.

The Industrial Gas Consumers Association of Alberta (IGCAA) expressed conditional support for the application, subject to modification of the proposed rate design. IGCAA suggested that the applied-for rate design should reflect a Local Delivery Service (LDS) and a different allocation of costs between intra-Alberta and ex-Alberta services. The proposed LDS would be a common toll applicable to natural gas transported by NGTL but intended to be consumed in the province, from any receipt point to any delivery point. IGCAA suggested that this LDS service be set at 6 cents/Mcf at 100 per cent load factor, in contrast to the current average receipt charge applicable to intra-Alberta deliveries of approximately 13.5 cents/Mcf. IGCAA stated that its proposal would maintain receipt point tolling as proposed by NGTL but only for natural gas destined to markets outside Alberta.

The Public Institutional Consumers of Alberta (PICA) believed that the Board should not approve the NGTL proposal as filed. It asserted that the Board should direct NGTL to submit a

[2] WEG comprises Pacific Gas & Electric Company , BC Gas Utility Ltd. and the Alberta Export Group, which includes Avista Corporation , Duke Energy Trading and Marketing, L.L.C., IGI Resources, Inc., Intermountain Gas Company, Northwest Natural Gas Company, and Puget Sound Energy, Inc.

complete and comprehensive cost of service study that would provide a more quantitative basis for determination of costs attributed to intra-Alberta service.

Other interveners including Canadian Forest Products (CANFOR), City of Calgary (Calgary), Consumers Coalition of Alberta (CCA), and GasAlberta Inc. (GasAlberta), also expressed concern with NGTL’s current cost allocation between intra and ex-Alberta services. These interveners expressed the view that the current cost allocation results in intra-Alberta customers effectively subsidizing ex-Alberta customers.

SEPAC and ProGas Limited (ProGas), although they did not object to NGTL’s proposed receipt point tolling methodology, also recommended that the application be denied. SEPAC submitted that it could not support the proposed separation of new services from NGTL’s investment base and revenue requirement. It also submitted that new lateral construction should continue to be integrated with NGTL and that there should be provisions for a shorter contract renewal notice period. SEPAC added that, absent of addressing its concerns, it would recommend maintenance of the postage stamp tolling methodology. In addition to issues with NGTL’s proposals for new services and new lateral construction, ProGas had concerns with the terms and conditions governing receipt transfers and term swaps, which it viewed as being overly restrictive.

Alberta Treaty Eight Bands (Alberta Treaty Eight), on behalf of itself and the Natural Resource Initiative, submitted that, as First Nations who own mineral rights, its concerns would be similar to those of smaller sized exploration and production companies engaged in resource development on First Nations territory. In that aspect, Alberta Treaty Eight stated that the First Nations’ interest and position would in general be aligned with those of SEPAC. However, as the First Nations were also contemplating cogeneration projects and hence would become natural gas consumers, it could see merit in IGCAA’s proposed LDS.

Phillips Petroleum Resources Limited (Phillips) urged the Board to deny the NGTL application. In its view, the factors that had led the Board to reaffirm the postage stamp rate design in *Decision U96055* were still valid and no compelling evidence had been presented to support such a fundamental change to the current rate design.

ATCO Gas (ATCO) stated that it did not accept NGTL’s proposed tolling methodology. It recommended that the Board deny the application and direct NGTL to adopt a toll design in accordance with the proposal outlined in ATCO’s intervention. ATCO proposed maintaining a separate receipt and delivery service with two rates, a Receipt Meter Toll and a Lateral Receipt Toll charged under the receipt service. The delivery tolls would be based on a six-zone structure. In each zone there would be two rates, an Intra-zone Toll applicable to all deliveries within the zone and a Traversing Zone Toll applicable to natural gas volumes that cross a zonal boundary. ATCO submitted that its proposed unbundling of NGTL’s rate structure would better reflect the cost causation principle of proper tolling design and would provide shippers with the opportunity to use the mainline, yet avoid the expense of using small-diameter pipelines.

1.4 The Hearing

The application was considered by the Board at a public hearing in Calgary, Alberta, commencing on October 4, 1999, before Board Members B. F. Bietz, Ph.D., J. D. Dilay, P.Eng., and Acting Board Member F. Rahnama, Ph.D. Appearances are listed in Appendix 1.

1.5 The Issues

The Board believes that in assessing the application it must, address the following issues:

- the acceptability of the industry consultation process, including whether the Board should consider the application as a single negotiated package;
- the relative merits of the various proposed rate designs;
- the proposed changes to the inclusion/exclusion of new services from utility rates;
- new facility construction and associated pricing;
- the proposed new terms and conditions of service; and
- Other related aspects of the proposed rate structure, including implementation of a Code of Conduct.

2 STAKEHOLDER CONSULTATION

2.1 The Industry Process

Views of NGTL

NGTL stated that by late 1996 shippers had become concerned with the potential impact of bypass on NGTL's rates under the current postage stamp rate design. Concurrent with industry's concern at this time, NGTL observed that the provincial government had indicated a belief that, as a matter of public policy, the postage stamp rate design was no longer required and that industry resolution of the issue of inefficient bypass of the NGTL system was desirable.

NGTL testified that while there was widespread industry acceptance of the need to replace the postage stamp rate design, there was little agreement as to what the new rate design should be. NGTL believed that this was attributable, in great part, to its unique system design, its complex operation, and the varied nature of its stakeholders. NGTL described its stakeholders as including those who sold, aggregated, or consumed natural gas. Natural gas was transported over varying distances in differing volumes and sold into distinct markets both within and outside of Alberta at different load factors. As a result, a variety of rate designs of varying complexity were possible.

NGTL stated that it had initiated discussions with its stakeholders regarding changes to its rate design in early 1997 and had continued the process, in one form or another, for two and one-half years, culminating in the present application before the Board. It strongly believed that its consultations, discussions, negotiations, and general communication with its stakeholders over this period was inclusive, open, and accommodating to all stakeholder views and interests. It acknowledged, however, that unanimity on all aspects of its present application was likely unachievable from the outset, given the disparate interests of those who would be impacted by the introduction of a new rate design. NGTL expected that although compromises would be made and some parties would remain unsatisfied, a reasonable consensus reflecting generally acceptable rate design principles could be reached.

NGTL described eight separate phases in its discussions with its industry stakeholders. Some phases were discrete in terms of issues, timing, and the number and nature of the participants. Other phases were more inclusive of parties and, on occasion, phases overlapped or parallelled each other. Some phases were characterized by a defined structure of negotiation and decision making. NGTL noted that generally the earlier phases included more participants than did later phases.

NGTL stated that in certain phases smaller groups met from time to time to consider issues that a larger group had failed to agree upon. Proposals from these smaller groups were disseminated to the larger groups for review and the resulting revisions were incorporated into the larger process. NGTL indicated that over 150 meetings between it and various stakeholders were held during the two and one-half years.

NGTL identified Phase 3, the Joint Industry/Government Task Force conducted in the summer and fall of 1997, as a particularly important period in its consultation process. Stakeholders engaged in this phase included producers, consumers, aggregators, marketers, utilities, industry associations, consumer associations, and government. Notwithstanding the extensive efforts of the parties during this part of the consultation process, including 50 joint and individual meetings attended by NGTL, no agreement was reached. NGTL believed that this was due in part to an impasse resulting from NGTL's reluctance to have its shareholders make a financial contribution as part of the transition to new rates to reduce the initial impacts of increased rates to shippers. Other issues included uncertainty over the level of service that would be provided under NGTL's proposal and the effects of allowing NGTL to provide new services at its own risk and reward.

While an overall settlement was not reached, NGTL believed that a general understanding and consensus on a number of important issues had been reached with a significant number of stakeholders. This consensus included:

- the desirability of a receipt point specific rate design,
- the need to maintain the current cost allocation between intra- and ex-Alberta services,
- the implementation of the new rates over a transition period of a number of years,
- an acknowledgement that both NGTL and its customers should share the financial impacts during the transition,
- the need to concentrate on the receipt component of the rate design so as to mitigate the extent of change, and
- an understanding that all issues would not be resolved at one time.

NGTL indicated that given the initial failure of the parties to reach a settlement on a new rate design and related matters, it filed a Service Offering and Rate Application in April 1998 with the EUB. It held several subsequent meetings with its customers to discuss its application. The results of these meetings prompted NGTL to suspend its application and to enter into direct discussions with CAPP, SEPAC, and TransCanada PipeLines Limited (TCPL). These parties signed a framework agreement (the Accord[3]), dealing with competitive issues facing the natural gas transportation industry, such as the imminent commissioning of the Alliance Pipeline and the merger of TCPL and NOVA Corporation. The Accord also confirmed the parties' commitment to negotiate changes to NGTL's tolls and services.

NGTL stated that as a result of the Accord negotiations among it, CAPP, and SEPAC began in earnest in May 1998 (18 meetings were held). NGTL believed that agreement had to be reached with these producer associations because the focus of its rate design proposal was on the receipt charge, which most directly affected producers who paid the receipt toll. It recognized that other stakeholders would have to be consulted and their views taken into account, but NGTL stated

[3] "Agreement on Natural Gas Pipeline Regulation, Competition and Change to Promote a Competitive Environment and Greater Customer Choice," dated April 7, 1998 and signed by CAPP, NOVA, NGTL, SEPAC, and TCPL.

that it first wanted to establish a framework with the producers. Such a framework could then be taken to the other stakeholders for discussion.

NGTL advised that the principles and concepts that had been the subject of intense discussion in the previous Joint Industry/Government Task Force (Phase 3), and for which NGTL believed there was significant industry consensus, were the same principles and concepts that formed the basis of its new consultation with CAPP and SEPAC. NGTL stated that by late summer—early fall of 1998, a framework for an agreement with CAPP and SEPAC had been accomplished. NGTL then communicated the terms of the settlement to the other stakeholders through bilateral talks.

Throughout the period August 1998 — February 1999, NGTL held 50 meetings with its stakeholders. In addition, NGTL met alone with IGCAA on eight occasions during this stage of consultation. NGTL stated that it, CAPP, and SEPAC genuinely took the concerns expressed by the various stakeholders into account as they carried out their negotiations. NGTL pointed to a number of compromises that it made as a result of the bilateral talks as evidence of its concern that the resulting rate structure was as inclusive of the needs of all stakeholders as possible.

NGTL submitted that the bilateral talks confirmed that the earlier industry consensus on the desirability of receipt point specific rate design had remained strong. It also argued that the bilateral discussions provided stakeholders, other than CAPP and SEPAC, with an effective opportunity to advance their positions and influence the terms of the MOU.

NGTL and CAPP signed the MOU on March 16, 1999. While it was party to the negotiations, SEPAC did not sign the MOU, citing dissatisfaction with certain provisions of the final version of the Agreement.

In summary, NGTL observed that its consultation process had spanned the past two and one-half years and had allowed the participation of each class of stakeholder. NGTL asserted that a number of alternative rate designs and service offerings were scrutinized by a broad section of the industry in a process that provided fair and ample opportunity for a full and frank exchange of views and positions. NGTL acknowledged that there could have been improvement to the consultation process in terms of involvement and providing information. For example, NGTL conceded that there was an unintentional oversight when certain stakeholders, such as Alberta Treaty Eight, were not consulted and that they should have been approached prior to a public notice regarding the Agreement. Further, it accepted that its consultation/negotiation process differed from the EUB's Negotiated Settlement Guidelines (Guidelines), which were issued during the process, but maintained that its process complied with the spirit of the EUB's Guidelines. Notwithstanding that, NGTL added that all stakeholders' concerns would not and could not have been entirely resolved by the process because of the differing self-interests of the many parties. NGTL concluded that its consultation process was extensive, rigorous, inclusive, and responsive to the concerns of all stakeholders.

Views of Others

A number of intra-Alberta natural gas consumers complained about the consultation/negotiation process conducted by NGTL. Intra-Alberta users generally expressed common concerns about both the relative inclusiveness of the process and the nature of the consensus that emerged from it.

IGCAA, ATCO, Calgary, GasAlberta, PICA, CCA, and CANFOR strenuously objected to the use of the industry consultation process conducted by NGTL as justification for the application. They argued that the process did not provide a meaningful opportunity for these parties to advance their substantive issues. IGCAA, for example, described the process as offensive to the principles of inclusion, fairness, openness, and regulatory oversight. These interveners disagreed with NGTL that an industry consensus had been achieved and was reflected in the application, maintaining that the process had excluded stakeholders other than CAPP and SEPAC from critical phases of the negotiations. All refuted any contention that CAPP or SEPAC represented their interests and they expressed dissatisfaction over the undue influence that they believed that CAPP had exerted in the process.

This group stated that, while some of them had participated in various phases of the industry consultation process, they believed that their views and concerns were given only perfunctory consideration by NGTL at critical stages. For example, reference was made to the assurances they believed that WEG had received from NGTL that no adverse impacts to the export delivery rate would result from the rate design changes. This, they believed, de facto limited NGTL's receptivity to potential rate design alternatives that would affect the export toll.

The interveners noted that there was no objective confirmation that the Agreement was based on consensus reached during the Joint Industry/Government Task Force phase. They observed that no summary reports arising from any of the stages of negotiation were presented, nor was any vote taken by NGTL.

The intra-Alberta users described the bilateral talks taking place over the summer, fall, and winter of 1998/1999 as primarily an opportunity for NGTL to convey the terms of the settlement reached with CAPP and SEPAC to those parties that had been excluded from the negotiations. They discerned little desire on NGTL's part to modify the significant terms of the MOU that it was developing with CAPP and SEPAC through genuine negotiations.

Several of these interveners pointed out that the negotiations did not conform to the EUB's Guidelines. CCA and CANFOR criticized NGTL for providing notice of the MOU when little if any opportunity was available to effectively advance their concerns. Alberta Treaty Eight stated that individual First Nations with interests in natural gas production and transportation were not invited to participate in any of the phases of the Industry Process. It observed that an MOU between CAPP and the Indian Resource Council that committed CAPP to engage in meaningful dialogue with First Nations was in place during the relevant period of industry negotiations. Notwithstanding the MOU, Alberta Treaty Eight observed that CAPP made little effort to directly involve First Nations in the negotiation process.

ProGas, an aggregator and marketer, asserted that NGTL's claim of "Industry Process" or "consensus" could not belie the fact that only NGTL and CAPP signed the MOU underpinning the present application. This, in the view of ProGas, hardly reflected an industry consensus. ProGas indicated that it had participated in early phases of the process. However, when the Joint Industry/Government Task Force broke down, no further opportunity was given to it or to others, apart from CAPP and SEPAC, to effectively make their case for either an alternative to postage stamp rates or to the proposed terms and conditions of service.

ProGas and PanAlberta also expressed concerns about the confidential nature of the Industry Process. ProGas argued that the confidentiality provisions prevented it from fully addressing issues raised in the hearing. PanAlberta criticized NGTL for selectively respecting the privilege, placing other parties that were not prepared to breach the rules at a disadvantage.

SEPAC confirmed that it was an integral participant in all phases of the industry consultation by NGTL. It stated that it had engaged in the discussions in the early stages, was a signatory to the Accord in April 1998, and held positions on the negotiating committees in the summer and fall of 1998. However, SEPAC ultimately did not sign the MOU. It indicated that its concern did not relate to the process of consultation/negotiation but rather to the fact that certain of its essential issues were not resolved satisfactorily in either the MOU or the application. SEPAC submitted that any industry consensus on the MOU or the application did not have the support of its 420 members.

CAPP and its individual members, including PanCanadian, Imperial, Shell, and Suncor, supported NGTL's characterization of the industry consultation process as inclusive and extensive. CAPP observed that it was a comprehensive process of negotiation and broad industry consultation over a two-and one-half-year period. CAPP believed that the MOU constituted a fair and balanced representation of a wide cross-section of industry views. CAPP submitted that the exclusive negotiations among it, SEPAC, and NGTL, following the collapse of the Phase 3 talks and the filing of NGTL's application in April 1998, was a reasonable and manageable approach for reaching a consensus with CAPP and SEPAC before taking the framework to the broader industry for discussion and input.

WEG indicated that none of its members was invited to discuss or negotiate the issues contained in the application but that it had received assurances from NGTL and CAPP that the export delivery toll was unchanged by the outcome of the negotiations and that holders of delivery service would be unaffected.

Views of the Board

The Board acknowledges that a movement away from the postage stamp rate design constitutes a significant change for industry and a shift in public policy. Such a change, directly and indirectly, impacts a wide class of stakeholders, including producers, consumers, aggregators, and marketers, all with diverse business interests. Under such circumstances, the Board believes that NGTL, as a regulated utility, has the responsibility and obligation to conduct a consultation process with its stakeholders that affords all constituents a reasonable opportunity to advance their positions and concerns. A process of consultation/negotiation cannot guarantee or ensure that any given position will be adopted, only that ample opportunity to propose, explain, persuade, and argue will be given to interested parties and that these positions will be genuinely taken into account.

The Board appreciates the challenges faced by NGTL over the past two and one-half years in initiating and conducting an Industry Process intended to reach a broad consensus on the replacement of postage stamp tolling. The magnitude of the change in tolling methodology, the disparate interests among classes of stakeholders, as well as the differing interests within distinct stakeholder groups, inherently limit the likelihood of achieving a consensus, let alone an agreement that would satisfy all stakeholders in all respects.

The Board acknowledges that NGTL's decision to concentrate its consultative efforts on the producer segment of the industry reflects the importance of this group to the NGTL system. Since it is the producers that would bear the brunt of the proposed rate design changes, clearly their concurrence with the proposed changes was critical to NGTL.The Board also believes however, that NGTL's consultative efforts in the early part of the Industry Process better adhered to the notion of inclusiveness and the provision of affected parties an appropriate forum to fully express their views and concerns. This was not the case in the later phases, which primarily engaged CAPP and SEPAC in negotiations. Intra-Alberta users were generally excluded from these important discussions during these later phases.

In the Board's view, however, the bilateral talks did not represent a genuine industry-wide consultation or negotiation. The Board accepts the evidence that stakeholders other than CAPP and SEPAC were unable to participate in the direct discussions in a meaningful way. The Board notes that even some parties were not invited to participate at all and received public notice of the MOU only after the major terms had been concluded. The Board believes that the bilateral discussions with certain parties could be more properly described as informational in that the primary purpose was to disseminate information. They were not conducted to achieve consensus, as there were no negotiations involved. Instead, NGTL's primary concern was to confirm with these parties the status of the agreement being reached with CAPP and SEPAC. The Board notes that NGTL apparently did not attempt to record the views of others, even in the form of notes or working papers. This is unfortunate, since such a process would have helped to assure stakeholders that at a minimum their views had been captured and considered.

In the Board's view, the exclusion of intra-Alberta users and export customers from meaningful consultation was based on a perception by NGTL that they would not be significantly affected by the new rate design. However, this resulted in a lost opportunity to effectively examine direct and indirect impacts on all stakeholders caused by a change to the rate design. Examining new rate design possibilities should have provided a valuable opportunity to study the issue as a whole and determine whether wholesale changes to the existing rate design were required or whether changes to only partial aspects were sufficient. The Board understands that it may not be possible to reach agreement upon various changes at one time. However, broader-based industry discussions may have afforded a means to put in place a more comprehensive plan, with the understanding that certain elements may not be resolved until a later date. To discount the position and concerns of others on the basis that they would experience no changes as a result of the proposed rate design fails to adequately take a long term view.

The Board, therefore, concludes that NGTL and CAPP failed to demonstrate that an industry-wide consensus was reached beyond a bilateral agreement between the two signatories to the MOU.

2.2 The Application as a Package

Views of NGTL

NGTL urged the Board to either accept the application without amendments or reject it outright. NGTL submitted that the present application was a package achieved through lengthy negotiations reflecting extensive compromises by a broad section of the industry with diverse and disparate interests. NGTL maintained that the application embodied an overall consensus of these parties and not a series of individual settlements or compromises that could stand alone if other parts of the application were rejected or modified. NGTL described the consensus as an industry-made solution, but a fragile agreement, vulnerable to dissolution and stakeholder pursuit of self-interest if any part were altered.

NGTL added that the industry’s best efforts had been engaged for the past two and one-half years and that, in the event that the Board rejected the package, it was unlikely that a better consensus could be reached expeditiously. The company expressed the strong view that if, as a result of the Board failing to approve the application, the process were to be extended, NGTL and its customers would face significant uncertainty surrounding rates and service conditions. This uncertainty, particularly in light of the upcoming start-up of the Alliance Pipeline, could negatively impact important commercial decisions facing shippers.

NGTL conceded that the process used to create the subject application did not strictly comply with the EUB’s Guidelines for Negotiated Settlements. The company did note, however, that the process it had used was consistent with the spirit of the Guidelines and, therefore, the Board should be able to either completely accept or reject the resulting agreement.

NGTL observed that it was still in the process of developing a Code of Conduct for affiliate transactions when the Agreement was being negotiated. However, NGTL disagreed with CAPP over the interpretation of a term in the MOU dealing with the Code of Conduct and maintained that the approval and implementation of the application could proceed without a finalized Code of Conduct. NGTL stated that in fact there was an existing Code of Conduct for NGTL and its affiliates. NGTL added that substantial progress had been made with CAPP on revising the current codes. Moreover, any concerns about undue affiliate preference could ultimately be remedied through recourse to the Board, a remedy that was not restricted by the development of a new Code of Conduct.

Views of Others

CAPP, PanCanadian, Shell, Suncor, Imperial, and WEG supported NGTL’s submission that the application should either be approved as a package without alteration or wholly rejected. CAPP added the proviso that its support for the entire application should not be interpreted as a precedent for its position on any particular element of the application. CAPP also requested that the Board condition its approval subject to CAPP and NGTL agreeing on an appropriate Code of Conduct for NGTL. CAPP also added that the language of the proposed tariff was under discussion with NGTL and that once the language was finalized, it would be filed as part of the application.

CAPP confirmed the view expressed by NGTL that the Agreement was a delicate balance of compromises among a wide cross-section of competing stakeholders. Many of the compromises were interlinked in the sense that individual stakeholder acceptance of the overall package was dependent on the give and take of other stakeholders. CAPP stated that elimination or modification of even minor parts of the application would greatly diminish or destroy the support of the participants. It noted that the MOU contained 22 components, all of which were necessary to bring parties to a settlement.

CAPP indicated that if the Board rejected the entire application or certain elements, it should provide some direction to the parties regarding its concerns about the concepts and specific terms of the application.

IGCAA, GasAlberta, Phillips, CCA, PICA, ATCO, Calgary, and ProGas submitted that NGTL's all-or-nothing position should be rejected, as the MOU was not negotiated in accordance with the EUB's Guidelines. The interveners maintained that if the Board accepted NGTL's view and treated the application as a package, it would be abdicating its statutory responsibility to independently set rates that are just and reasonable for all customers. Calgary contended that the take-it-or-leave-it nature of the application should not be used to relieve NGTL of its evidentiary burden or restrict the Board in exercising its regulatory scrutiny of all components of the application.

ATCO, Calgary, SEPAC, and Phillips argued that the application should be denied in its entirety, as it did not reflect even a consensus between NGTL and CAPP, let alone an industry agreement. They pointed out that CAPP's endorsement of the application was conditional upon a satisfactory Code of Conduct for NGTL being finalized, while NGTL disagreed that a completed Code of Conduct was required before its implementation. Further, ATCO and Phillips submitted that there was discord between NGTL and CAPP over the definitions of terms in the tariff, including export delivery points, laterals, and mainlines.

GasAlberta also expressed scepticism about the inviolable nature of the application, noting, for example, that the deletion of the provision regarding the compulsory minimum annual administrative fee of $48 000 was unlikely to cause a collapse of the Agreement.

SEPAC argued that the application contemplated bypass of Board approval for new services, which was contrary to Section 36.1 of the Gas Utilities Act. Therefore, without an appropriate amendment to the legislation, the application as submitted could not be approved as a whole.
A number of parties, including ATCO, CCA, GasAlberta, and PICA, submitted that if the Board rejected the application outright, it should also enunciate its views regarding the nature of future negotiations with the broader industry. Furthermore, the Board should direct that a cost of service study be prepared and provide the appropriate principles, guidelines, and time frames regarding rate design and conditions of service.

PanAlberta submitted that the application should be accepted or rejected as a package. It argued that NGTL and CAPP had entered negotiations with the expectation that compromises would be made to their positions and that if a settlement emerged, it would be approved or denied by the Board as a package. It contended that for parties to willingly consummate negotiated settlements, they must be confident that the Board would not selectively accept or reject parts of the settlement.

PanAlberta maintained that the Board should ignore any implied threats that the NGTL system would be thrown into continuing uncertainty if it rejected the package. NGTL and CAPP, it observed, had clearly accepted the risk that the application might be refused by advancing it on an all-or-nothing basis.

Views of the Board

The Board is empowered under the Public Utilities Act and the Gas Utilities Act to set just and reasonable rates. The exercise of this statutory duty cannot be constrained by the submission of a rate design agreement entered into by a gas utility and some or all of its stakeholders. The Board is obliged pursuant to its enabling legislation to independently assess, consider, and determine whether a proposed rate design meets the public interest test of just and reasonable rates.

In carrying out its legislated obligation, the Board may consider negotiated settlements proffered by parties. However, the fairness of a negotiated process is central to the Board's willingness to regard the negotiated settlement as a package. The circumstances under which consideration will be given to such a package are set forth in Section 12.2 of the EUB's Negotiated Settlement Guidelines. One significant requirement of those Guidelines is that parties with an interest in the application must be given the opportunity to participate fully in the negotiation process.

As noted in Section 2.1 of this decision, it is the Board's view that the negotiations that culminated in the MOU were not conducted in accordance with the Guidelines. In fact the Board notes that NGTL did not claim otherwise but rather stated that only the spirit of the Guidelines was met. Only NGTL, CAPP, and SEPAC were engaged in the direct negotiations and only NGTL and CAPP actually signed the Agreement. As stated earlier, it is the Board's view that, while CAPP members are clearly the major users of the NGTL pipeline, the Board believes that NGTL and CAPP have overstated the degree of consensus among all segments of the industry.

The Board is also concerned about the Code of Conduct, which remains a contentious issue between NGTL and CAPP. These two parties are clearly not in agreement on the necessity of a completed Code of Conduct prior to the implementation of the changes proposed in the application.

Accordingly, the Board does not view the MOU as a true negotiated settlement as contemplated by the Guidelines and is not prepared to accord the same treatment to the MOU that might otherwise be the case had it complied with the Guidelines.

NGTL and others have argued that in the event that the Board determines that it cannot accept the application in its entirety, it must wholly reject it, as it represents compromises by both CAPP and NGTL that would not otherwise have been acceptable absent all the elements of the Agreement. It was argued that approving parts of the Agreement would be unfair to these parties and would also tend to discourage future negotiated settlements.

While the Board remains a strong supporter of negotiated settlements and is cognizant of the delicate balance such agreements may represent, the Board does not find these arguments in this case to be persuasive. As described earlier, it is solely the Board's responsibility to determine whether an application meets the public interest and, in discharging this duty, it is invested with the discretion to approve or reject an application in its entirety or in part. The parties, in turn, have a full and complete opportunity to assess the results of the Board's decisions and to determine whether they can work within the terms of the Board's approval.

In the present case, the Board is not prepared to accept the application as a whole and intends to examine its various elements individually and collectively in order to determine whether the proposed rate design and related terms and conditions are in the public interest.

The Board, in reaching its decision that it must examine and decide upon the individual aspects of the application, was particularly struck by a number of positions taken at the hearing. The first was the almost complete consensus by all the parties to the hearing that the new dynamics of the Alberta natural gas marketplace had now made fundamental changes to the NGTL tolling methodology necessary. From the testimony, it was apparent that the market forces driving the need for these changes were growing and that, presumably, such changes should be made sooner rather than later. Certainly it was NGTL's position that it required a decision from the Board in a relatively short time in order to deal with, for example, pipe-on-pipe competition.

Second, there was clear concern raised at the hearing that if the Board were to reject the application in its entirety, this would likely result in a second round of potentially very time-consuming negotiations between the parties. Furthermore, even with clear direction from the Board, there appeared to be a significant likelihood that any future negotiations, given the diverse interests even among the members of CAPP and SEPAC, would fail to reach consensus. This, in turn, would result in a high degree of uncertainty or, alternatively, could cause NGTL to abandon negotiations and once again prepare a new application on its own.

The Board appreciates that in evaluating each of the components of the application, it is effectively assigning benefits and costs in a manner that individual parties may not view as being to their optimum benefit. The Board does so, however, in the belief that given the present rapidly changing marketplace for natural gas, providing certainty through timely decisions based on clearly set-out principals is in the best interests of NGTL, its stakeholders, and the public. The Board expects that parties, if they find aspects of the Board's decision truly unacceptable, will file the appropriate requests for review and variance. The Board believes that this result, however, is distinctly preferable to creating market uncertainty, which the Board believes would occur if the Board were to reject it completely, since it is unwilling to accept the application in its entirety,

3 RATE DESIGN

NGTL submitted that a change to its current postage stamp tolling methodology was needed. NGTL recognized that natural gas resource development in Alberta has been greatly influenced by the postage stamp rate design. It also submitted that its current system configuration, which was the result of postage stamp rates, had made it possible for many producers to develop natural gas resources without regard for the distance to the border delivery points. NGTL asserted, however, that significant recent changes had occurred that necessitated a change to its rate design. In particular, NGTL described the bypass proposals that had emerged since the GRA and the recognition among industry participants, through the execution of the Accord, that greater customer choice and an increasingly competitive environment for natural gas transportation was desirable. NGTL submitted that in the new market reality of pipeline competition it should have the appropriate tools to compete. NGTL observed, however, that it was only recently that there had been sufficient industry support for a move away from the current tolling methodology.

In response to NGTL's applied-for tolling design, only ATCO submitted its own alternative proposal. IGCAA suggested a modification that would introduce a local rate for local service (intra-Alberta service). In contrast, others suggested that maintaining a postage stamp approach would continue to be the desired option.

3.1 An Overview of NGTL's Proposal

Views of NGTL

NGTL submitted that the proposed rate design and associated terms and conditions of service constituted a significant change from its current postage stamp tolling methodology. Approval of the application would necessitate changes to both determination and allocation of the revenue requirement and would have implications for the provision of new facilities. NGTL submitted that the paramount objective of its proposed rate design was to increase cost accountability without substantially affecting the current market liquidity, flexibility, and simplicity afforded through pooling of natural gas on its system.

NGTL submitted that its proposed rate design, consistent with the provisions of the MOU, focused on allocation of the receipt component of its revenue requirement in a manner that would reflect the cost to transport natural gas. The relative allocation of the revenue requirement to intra-Alberta and ex-Alberta delivery services remained unchanged. This, NGTL submitted, was consistent with the desire to limit the magnitude of changes for its shippers. NGTL added that a multiyear Transition Period with contribution by all parties to the transition costs was also incorporated, to provide customers with the opportunity to adjust business and investment decisions.

3.1.1 Separation of Receipt and Delivery Rates

NGTL observed that under the current postage stamp rate design, the company charges separate rates for receipt and delivery contracts. By paying the receipt charge, a customer basically earns access to the NGTL pipeline system, whereas the delivery charge paid by either the same customer or another allows natural gas to leave the system. NGTL submitted that separate receipt and delivery contracts had made pooling of natural gas possible on the NGTL system and greatly contributed to the current service flexibility and simplicity. For example, separate receipt and delivery contracts had contributed to the much-desired market liquidity facilitated by NIT. NGTL submitted that the NIT concept was developed through a collaborative process between NGTL and industry. The existence of a single supply pool created a single market price and thus provided for maximum price discovery.

NGTL asserted that the new rate design would preserve the existing contractual framework through separate treatment of receipt and delivery services. Delivery rate calculation would be left unchanged. The intra-Alberta delivery charge would continue to be set at its current level of $0/Mcf, while the ex-Alberta delivery charge would continue to be recovered through a single rate.

NGTL submitted that with the continued separation of receipt and delivery rates, both intra- and ex-Alberta delivery customers would not be affected by its proposed tolling design. NGTL stated that it would continue to recover charges to intra-Alberta customers for both receipt and delivery service solely through the receipt charge. It noted that since the majority of intra-Alberta natural gas users hold only delivery contracts, they should not be negatively impacted by the proposed rate design.

3.1.2 Receipt Point Specific Rates

NGTL submitted that its proposed rate design was based on the premise that the revenue requirement associated with receipt service would be allocated to each firm service receipt point on its system. The allocation would be determined using cost factors that reflected both the relative distance from the receipt point to the major Alberta border delivery points (Empress/McNeil and Alberta-BC) and the unit cost differences attributable to variations in pipeline diameter. NGTL submitted that since approximately 85 per cent of the natural gas flow is destined to the export market, the major border delivery points were deemed to be the delivery points for all natural gas flowing on NGTL.

Under the proposed tariff, each receipt point on the NGTL system would have its own rate, reflecting the length and the pipe diameter for all the facilities required to flow natural gas along a path from that specific receipt point to the major delivery points (Figure 1). Revenue requirement, associated with receipt service, would be allocated among all receipt points. NGTL added that each transportation path would contain a mix of facilities of various vintages. It assumed that cost effects due to the vintage of the facilities would be averaged over the paths.

NGTL rationalized pipe diameter as an appropriate cost factor by the fact that, unlike other major North American pipelines, NGTL’s configuration consisted of a series of small-, medium-, and large- diameter pipes constructed throughout the province. NGTL submitted that its proposed rate design accounted for the fact that smaller-diameter pipe has a lower price on a mileage basis but would have a higher unit cost based on the amount of volume that can actually move through the system. NGTL concluded that simple geographical zoning would not accurately reflect the cost factors that would affect receipt point volumes and distances of haul.

NGTL described in detail the calculation of the allocation factors used to determine the revenue requirement at each receipt point. The calculation depended on two determinations: the Unit Cost

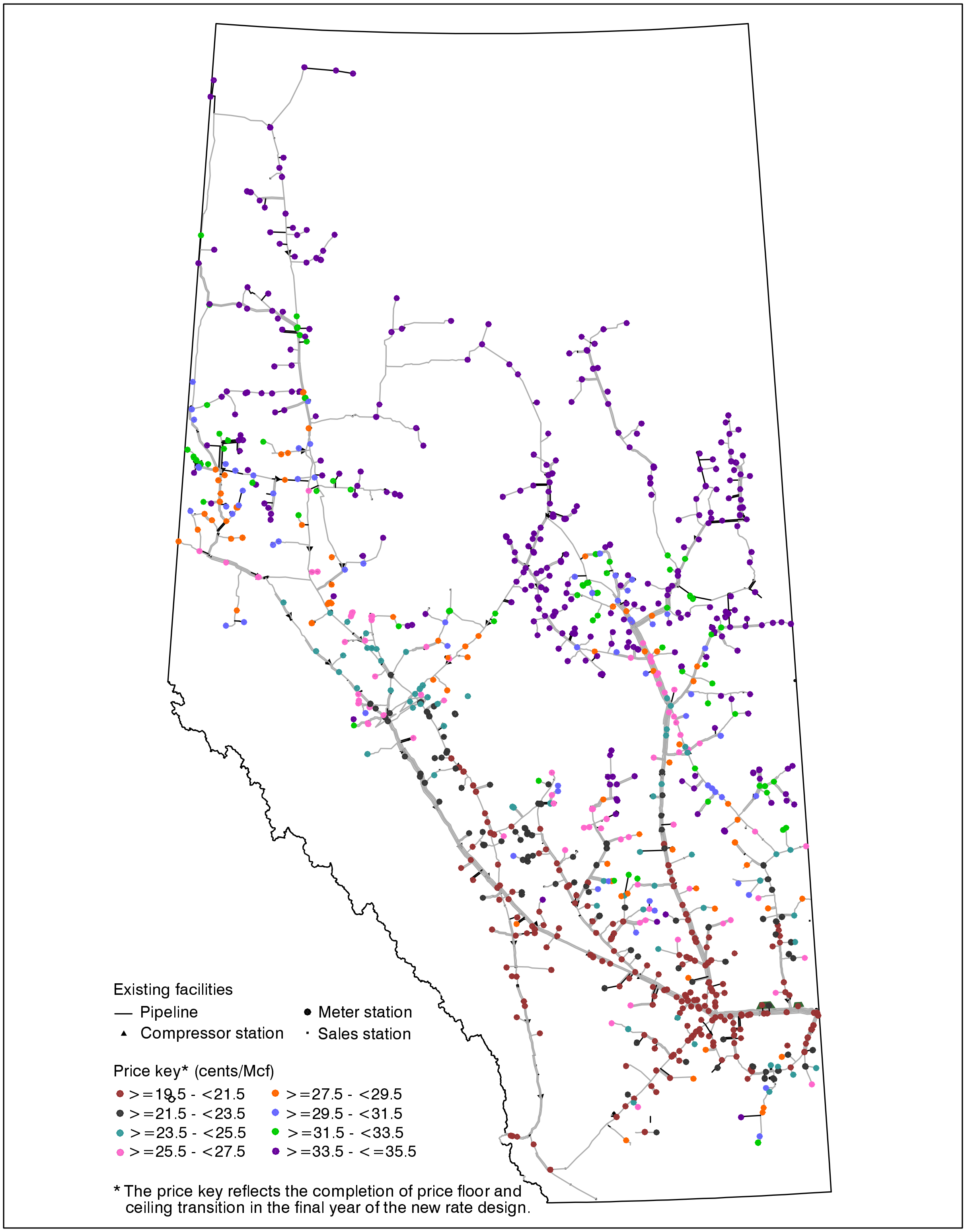

Figure 1. Receipt point specific rates as proposed by NOVA Gas Transmission Ltd.
Application no. 990157
NOVA Gas Transmission Ltd.
Decision 2000-6

Index and the Weighted Average Path. The Unit Cost Index was designed to determine the appropriate cost factors for pipe and compression for each receipt point. It had been developed to reflect the cost of each pipe diameter relative to NPS 48 pipe. In the determination of the Unit Cost Index, NGTL submitted that it had used the average of the actual capital cost of compression and actual cost of constructing pipe on the NGTL system over the period 1992-1997. NGTL added that the related operating and maintenance costs used were actual costs for the 1995-1997 period. NGTL submitted that the Unit Cost Index would function as a proxy for the difference in the relative transportation cost of using various pipe diameters.

NGTL described the Weighted Average Path as a proxy for the path for volumes of natural gas entering the system from the receipt point to the major export delivery points. NGTL explained that the relative cost of each diameter of pipe at each receipt point was expressed as the receipt point specific contract demand multiplied by the Unit Cost Index and by the Weighted Average Path for the diameter pipe in question. The relative cost of the receipt point itself would then be the sum of the relative costs over all diameter pipes located on the path from that receipt point to the border. NGTL referred to this as a proxy to reflect the cost of transporting natural gas from each subject receipt point. The allocation factor at each receipt point would then be the quotient obtained when the relative cost of the receipt point in question was divided by the aggregate of the relative costs of all receipt points.

NGTL concluded that the allocation factor for each receipt point would represent the portion of the total revenue associated with receipt service that needed to be recovered at the said receipt point, making it possible to determine a receipt point specific rate.

To simplify the applied-for rate design, NGTL proposed eliminating the commodity charge. NGTL stated that implementing a commodity charge in a receipt point specific methodology would require calculating receipt point specific commodity charges. Since the commodity charge represented only 1.6 per cent of the total revenue requirement, NGTL noted that its elimination would simplify the rate design and associated business processes without materially affecting customers.

NGTL submitted that the fact that rates at specific receipt points were influenced by their location from the border should not adversely impact intra-Alberta shippers. Intra-Alberta customers and any other customers could continue to purchase natural gas from any receipt point by virtue of separate receipt and delivery contracts. NGTL submitted that the fact that natural gas could originate from any receipt point to connect with any delivery point, regardless of whether there was in fact a physical connection, was a manifestation of the benefit of the integrated nature of its system. NGTL added that the large terminal deliveries at the export points were the primary source of upstream pipeline transmission economies, which, according to NGTL, materially benefited intra-Alberta gas flows. NGTL expressed the view that without the export flow the scale of its system would be significantly different and the unit costs of natural gas transportation for intra-Alberta use would be higher.

3.1.3 Price Floor and Ceiling over a Transitional Period

NGTL submitted that a mechanism to mitigate the impact of rate changes was necessary, given that rates for some receipt points, depending on their location, might be higher or lower than the current postage stamp rate. For this reason, a Price Floor and Ceiling mechanism was introduced to set a maximum and minimum price for receipt service rates.

In accordance with the provisions of the Agreement, NGTL submitted that it was proposing a four-year Transition Period from the existing postage stamp rate to the proposed receipt point specific rates. The maximum receipt price (Price Ceiling) would be increased by 2 cents/Mcf per year over the Average Firm Receipt Service Price (AFRSP) for each year of the four years. The minimum receipt price (Price Floor) would be decreased by 4 cents/Mcf per year under the AFRSP for each of two years. NGTL defined the AFRSP as the Adjusted Firm Receipt Revenue Requirement divided by the Firm Receipt Contract Demand. The AFRSP was to be calculated annually based on estimates for the upcoming year. Based on the 1999 average receipt price, the price floor and ceiling over the Transition Period would be 5.5 cents/Mcf and 21.5 cents/Mcf respectively.

The following table illustrates the applied-for Price Floor and Ceiling over the four-year transitional period:

	Commencement Date	January 1, 2001	January 1, 2002	January 1, 2003
Price Ceiling	AFRSP + 2 cents/Mcf	AFRSP + 4 cents/Mcf	AFRSP + 6 cents/Mcf	AFRSP + 8 cents/Mcf
Price Floor	AFRSP – 4 cents/Mcf	AFRSP – 8 cents/Mcf	AFRSP – 8 cents/Mcf	AFRSP – 8 cents/Mcf

NGTL observed that the implementation of the Price Floor and Ceiling would result in a revenue shortfall during the Transition Period. The provisions of the Agreement called for NGTL, as well as customers, to contribute towards this shortfall for each of the two years following the commencement date. NGTL and customer contributions were set at $25 million and $20 million respectively each of the first two years of the Transition Period. NGTL did not address the relationship between rates at specific receipt points and the AFRSP beyond the Transition Period.

3.1.4 Rate Design Principles

NGTL submitted that its proposed rate design incorporated key attributes of a proper rate design. The proposed tolling methodology, NGTL stated, properly reflected the criteria of cost causation, simplicity, ease of administration, stability, fairness, and avoidance of undue discrimination. In addition, the proposed rate design provided NGTL's customers with a transitional period to help them adjust to the move away from postage stamp rates.

NGTL explained that the principle of cost causation, and hence efficiency, was satisfied since the rate design would account for the most important cost relationships, i.e., pipe diameter and distance. The criterion of simplicity was also satisfied since all rates would be published and each customer would know the applicable rate for each of the receipt points. NGTL conceded that there might be some initial complexity in the rate calculation for each receipt point but was confident that once the framework was established it would be quite easy to administer.

NGTL observed that its proposal would provide rate stability since it would discourage commercially viable but economically inefficient bypass. With regards to fairness, NGTL stated that its proposal considered in its entirety satisfied the fairness criterion. While producers in northern regions of the province would pay higher rates than their counterparts to the south, these differences in tolls at various receipt points would not constitute undue discrimination, since these rate differences properly reflect cost differences. Furthermore, NGTL observed that CAPP shippers had consented to such distributional changes as part of the Agreement.

3.1.5 Cost of Service Study

NGTL stated that it had not performed a cost of service study on an unbundled basis in order to verify the proposed cost allocation among its service offerings. NGTL noted that given the integrated nature of its system, coupled with the long-standing use of postage stamp rates, it had not historically accounted for its costs in a way that would allow it to segregate the costs of providing either intra- versus ex-Alberta service or receipt versus delivery service.

NGTL submitted that all of its costs should be classified as fixed. NGTL proposed to roughly divide its revenue requirement between receipt and delivery services, such that the cost for firm service to ex-Alberta markets when compared to intra-Alberta service was set at a ratio of 2:1. NGTL asserted that the logic of such a split was confirmed by the results of its distance of haul study (Section 3.1.6).

3.1.6 Distance of Haul

NGTL submitted distance of haul studies for the years 1996, 1997, and 1998 to illustrate average distances of haul on the NGTL system during each of the calendar years. Average distances of haul were calculated for both intra- and ex-Alberta deliveries and the ratio between the two averages was determined. NGTL had used this ratio in the past as a proxy to determine the cost allocation between intra- and ex-Alberta services.

NGTL noted that the calculation methodology consists of satisfying the requirements of a particular delivery station with available receipt volumes from upstream stations on a pro rata basis. This process continues downstream in a north to south general direction until all the receipt volumes have been allocated. The methodology is based on physical flows for a typical day, which, according to NGTL, occurs at least 80 per cent of the time.

In its most recent distance of haul study (1998), NGTL collected data from 980 receipt meter stations and 170 delivery stations on its system. NGTL, however, only examined volumetric data for 38 intra-Alberta and the 4 major border delivery points. NGTL submitted that it only examined 38 intra-Alberta delivery points since detailed calculations for all of the remaining intra-Alberta delivery stations would not materially affect the overall results. The intra-Alberta delivery points that it considered, including the extraction plants, represented 83.04 per cent of total intra-Alberta deliveries over the study period. The 4 border delivery points that it considered (Empress, McNeil, Gordondale, and Alberta-BC) represented 98.67 per cent of ex-Alberta deliveries.

The study found that approximately 87 per cent of natural gas on the NGTL system had been delivered to the border stations. The average distance of haul was 253.32 km for intra-Alberta deliveries and 547.88 km for ex-Alberta deliveries, giving a ratio of ex-Alberta to intra-Alberta deliveries of approximately 2.16:1. NGTL noted that these results were consistent with those of 1997 and 1996 studies, as well as with others done in earlier years, where the ratio had varied from 2.1:1 to 2.4:1.

NGTL observed that the Board had accepted NGTL's distance of haul study as recently as *Decision U96055*. In NGTL's view, its distance of haul methodology was still appropriate and the results from the study could continue to be used to confirm the reasonableness of the allocation of costs between intra- and ex-Alberta services.

3.1.7 Required Changes to the Revenue Requirement

In order to facilitate incorporating its new rate design, NGTL proposed a change to the manner in which its revenue requirement is determined. While NGTL's revenue requirement would continue to be defined by the Cost Efficiency Incentive Settlement (CEIS), the resulting total revenue requirement would be adjusted by NGTL's contribution to the transition costs over a two-year period. It would also be adjusted by revenue variations, subject to a collar, attributed to term-differentiated tolling, including premiums on short-term services. Another significant change was that after a short period NGTL would no longer build customer-specific receipt and delivery facilities other than meter stations and tie-ins. As a result, these would be excluded from its rate base.

3.1.8 Rate Calculation Process

NGTL described the different steps required in the calculation of rates. Basically, Total Revenue Requirement would be determined in accordance with the CEIS. Revenue from other sources, such as interruptible services, would be subtracted to obtain the Firm Service Revenue Requirement. Given total contract demand (receipt and ex-Alberta contract demand), Firm Service Revenue Requirement could then be separated into Firm Service Receipt Revenue Requirement and Firm Service Delivery Revenue Requirement. Firm Service Delivery Price would then be calculated in a way similar to the current tolling methodology.

Firm Service Receipt Revenue Requirement would need to be adjusted to reflect the over- or under-collection of revenues in the previous year as a result of variable revenues associated with term-differentiated tolls. Firm Service Receipt Revenue Requirement would also be adjusted by the amount that NGTL had agreed to contribute to the cost of transition. This would result in the Adjusted Receipt Service Revenue Requirement that would need to be recovered at the aggregate of the receipt points.

The Firm Service Receipt Price would then be calculated for each receipt point. This would be done by dividing the Adjusted Service Revenue Requirement allocated to the receipt point (using the allocation factors as described in Section 3.1.2) by total volume contracted at the particular receipt point. Since the application of the Price Floor and Ceiling would result in a revenue discrepancy caused by the under-collection of revenue from receipt points above the ceiling, the

Firm Service Receipt Prices would then be adjusted through an iterative process. This would produce the final daily Firm Receipt Service Prices at 100 per cent load factor.

For billing purposes, the daily Firm Receipt Service Prices would then be converted to Monthly Receipt Service Rates.

Views of Others

Member producers, including Imperial, Suncor, and Shell did not submit written evidence but supported CAPP's acceptance of the proposed rate design. Their position was that receipt point tolling as filed represented a balanced and equitable replacement to postage stamp because it would provide better economic signals through improved cost causation.

PanCanadian also agreed with NGTL's proposed rate design and believed that it represented a significant improvement over the current postage stamp. PanCanadian expressed the view that receipt point specific tolling that takes into account the distance that natural gas has to travel provides better signals to shippers about the costs they impose by locating at different points on the NGTL system.

Regarding proper cost allocation between receipt and delivery services, PanCanadian offered the view that NGTL's proposed split was reasonable. However, it added that, given that receipt and delivery services are provided by common facilities, any specific cost allocation ratio between the two services would be difficult to prove. PanCanadian considered that NGTL's assumption that all natural gas would flow to the border could distort the receipt point cost allocation. However, given the price floor and ceiling proposed by NGTL, the company believed that such distortion may not be significant. PanCanadian also noted that with the intra-Alberta delivery charge proposed to remain at zero, the fee clearly reflects the Agreement and not the actual cost of providing delivery service to intra-Alberta customers.

WEG submitted that NGTL's rate design would continue to enhance liquidity, flexibility, and market efficiency. As holders of over 50 per cent of the firm service delivery at the Alberta-BC border, the WEG group asserted that NGTL's proposal appeared to have the least detrimental impact on the much-desired NIT market and on the gas supply arrangements of its members.

WEG noted that several of its member companies were regulated utilities that bear ongoing obligations to demonstrate purchase of least-cost supply alternatives. Any cost shifting to ex-Alberta shippers, in WEG's view, could force these utilities to take Alberta-sourced natural gas at lower load factors and to seek incremental supplies from other sources.

WEG submitted that it supported NGTL's distance of haul study. It believed that this approach would continue to be fair and workable in practice. WEG expressed the view that intra-Alberta customers should, in fact, pay more than their current charge for natural gas transportation on NGTL as they were afforded access to provincial supplies without any contractual financial obligation. Moreover, WEG observed that current provincial legislation provided additional security to intra-Alberta customers through a pre-emptive right to natural gas supply.

ATCO submitted that NGTL's rate design proposal should be rejected. ATCO believed that many of the toll design ideas upon which NGTL based its application were without precedent and did not adhere to the most fundamental criteria of proper rate making, i.e., cost causation, simplicity, and fairness.

According to ATCO, the cost causation criterion was violated when NGTL allocated its costs to receipt points based on the assumption that all natural gas on its system was destined to the export points. This, in ATCO's view, would discriminate against intra-Alberta natural gas consumers, as they would be forced to pay for capacity to the border regardless of the location of the desired delivery point. ATCO believed that under NGTL's proposal, end-users that have chosen to locate in proximity to natural gas production would effectively subsidize export customers. Moreover, ATCO submitted that NGTL's proposal to use differences in costs based on pipe diameter as the basis for its proposed rate design was not supported by the submitted cost data.

ATCO stated that NGTL violated the cost causation principle on two additional counts. First was when it failed to support its cost allocation between intra-Alberta and ex-Alberta services with a cost of service study. The second was when it identified, through its own distance of haul study, that intra-Alberta gas moved less than 50 per cent of the distance travelled by ex-Alberta volumes yet would pay more than 100 per cent of the cost to move natural gas to the intra-Alberta market.

ATCO submitted that NGTL also failed to satisfy the simplicity criterion of sound rate design. ATCO stated that each receipt point would have its own rate, with the possibility of wide variation in rates among receipt points in close proximity.

ATCO also did not believe that NGTL's proposal met the rate design principle of fairness. ATCO stated that the proposed rate design not only would discriminate against consumers in Alberta but also against producers who happened to be located on laterals rather than mainlines and thus would be required to pay higher rates. In ATCO's view, NGTL's proposal precluded competition in the higher-cost facilities and failed to offer shippers the choice of avoiding small-diameter lateral pipeline but still using the mainline.

IGCAA submitted that receipt point specific tolling, while workable for natural gas destined to the export market, would not be appropriate for natural gas delivered to the intra-Alberta market. Like ATCO, IGCAA had concerns with pricing the receipt service at points based on the distance to the border. IGCAA believed that the practice would create a fundamental inequity in the tolling methodology for natural gas moved to intra-Alberta delivery points.

IGCAA noted that there was no justification for the premise that the same intra-Alberta market could be accessed by shippers for very different rates, varying from the minimum receipt charge of just over 5 cents to over 21 cents. This, IGCAA submitted, would promote bypass of the NGTL system within Alberta.

IGCAA believed that NGTL's request to maintain the current cost allocation was unfair. NGTL, in IGCAA's view, had provided no clear assessment as to the level of costs that were actually incurred to serve the Alberta market. IGCAA noted that the size of the intra-Alberta market had not changed over the past ten years, yet NGTL's cost of service had more than doubled. Any benefit intra-Alberta shippers had received as a result of NGTL's expansion was, IGCAA believed, limited.

IGCAA considered that a good proxy for intra-Alberta cost allocation was the distance of physical haul between an Alberta delivery point and the nearest receipt point or points necessary to meet demand at that delivery point. Using this methodology, IGCAA determined that the average distance of haul to serve Alberta delivery points was 52 km compared to 560 km to serve ex-Alberta markets. Accordingly, IGCAA did not agree with NGTL's distance of haul methodology, stating that it represented an inaccurate portrayal of natural gas flows on the NGTL system and seriously overestimated the average distance of haul to Alberta delivery points. IGCAA submitted that the ratio of the distance of haul of ex-Alberta to intra-Alberta deliveries was 10:1. However, given the added value of supply and market flexibility as proposed by NGTL, IGCAA recommended that a ratio of 5:1 be used for the determination of proper cost allocation between ex-Alberta and intra-Alberta services.

SEPAC's position was that unless certain proposals related to new services, construction of laterals, and renewal notices were altered, there should be no change to the current tolls and tariffs.

ProGas stated that it had no objection to the receipt point tolling methodology being proposed. It did object, however, to the terms and conditions of service and other elements of the Agreement and for this reason preferred that the current rate design and terms and conditions of service be retained. PanAlberta expressed neither support nor opposition to the application. Phillips, on the other hand, was of the view that no compelling evidence was introduced that would justify a move away from current tolling methodology.

Alberta Treaty Eight submitted in argument that the NGTL rate proposal would hamper development with respect to certain Indian lands, particularly in the north at the extremities of the NGTL system where First Nations tend to own land. Alberta Treaty Eight argued that, as mineral rights owners, they shared the same concerns as those of small-size producing companies except that they did not have the same flexibility to mitigate higher northern transportation rates by directing their activity to regions in the south.

Alberta Treaty Eight noted that NIT could be best preserved by keeping it paired with postage stamp. Any cost accountability issues would then need to be addressed as separate issues, outside the rate design.

Several intra-Alberta consumers other than ATCO and IGCAA did not submit evidence but presented arguments with a common theme, which was their belief that rates for intra-Alberta natural gas transportation should be lower. It was their position that receipt charges applicable to natural gas consumed in the province are ultimately recovered from customers through natural gas prices and that these transportation charges, based on the proposed cost allocation, were excessive. CrossAlta Gas Storage and Services Limited took the position that any new NGTL tolling structure should be designed so as not to affect the storage market through loss of access or loss of market liquidity.

Calgary recommended that the Board deny the application. Calgary's position was that the existing rate design methodology, though not perfect, best served the needs of its citizens. It added that NGTL did not provide sufficient evidence to allow the Board to conclude that its proposed rates were just and reasonable.

Calgary took the position that NGTL had considered only distance and pipe diameter and had failed to recognize cost drivers such as vintaging. The proposed rate design, in Calgary's view, would yield rates that would penalize shippers located on smaller-diameter pipes even though sizing of the different pipes was at the sole discretion of NGTL.

Calgary considered that the major weakness of NGTL's applied-for rate design was the failure to provide an appropriate toll structure for intra- versus ex-Alberta services. Instead, Calgary noted that NGTL proposed the same methodology that was in place some ten years ago when the intra-Alberta market accounted for a much larger percentage of total system flow.

In Calgary's view, the justification for maintaining the current cost allocation was flawed. Calgary believed that the intangible benefits that NGTL considered accruing to intra-Alberta customers were equally applicable to ex-Alberta shippers. Furthermore, the distance of haul studies used as a proxy for cost allocation were applied in an oversimplistic manner and had serious internal flaws. For example, Calgary submitted that NGTL's distance of haul study did not account for all the intra-Alberta volumes and maintained that if these volumes had been accounted for, the average intra-Alberta distance of haul could have been reduced. Calgary concluded that a 45 per cent cost allocation to intra-Alberta service would be the maximum appropriate amount.

CCA recommended that the application be rejected, varied, or sent back for further negotiations. In its view, the cost assigned for the combined intra-Alberta receipt and delivery charge was excessive. CCA noted that over the last ten years NGTL rates for intra-Alberta customers had increased significantly even though demand had been relatively flat.

CCA considered that NGTL's distance of haul study was not reflective of the actual intra-Alberta distance of haul. In CCA's view, the intra-Alberta distance of haul should have been dropping as the system expanded northward. The CCA also expressed concern with the inclusion of make-up natural gas at the extraction plants in calculating the intra-Alberta distance of haul. It argued that such an inclusion would have the effect of significantly increasing the average intra-Alberta haul, as shrinkage natural gas has a distance of haul closer to export delivery points than any other remaining intra-Alberta natural gas delivery. Therefore, the CCA submitted that an exclusion of extraction plant volumes in calculating distance of haul would be fair in that it would allow for the design of a more appropriate intra-Alberta rate.

GasAlberta submitted that it did not believe that NGTL’s proposal to move to a receipt point specific tolling design system would have an adverse effect on its rural Alberta customers, including those in very remote areas, since the average intra-Alberta receipt toll would remain at 13.7 cents Mcf. However, GasAlberta did object to the proposed cost allocation between the receipt and delivery services. It recommended that the Board institute a 40/60 receipt-to-delivery cost allocation ratio.

PICA, representing public hospitals and educational institutions, submitted in argument that since NGTL was primarily an export pipeline system, requiring the company to collect relatively more of the charges at the point of export would seem to be reasonable. Moreover, a higher export delivery charge would have the impact of lowering the NIT price at the point of sale to intra-Alberta customers. For this reason, PICA noted that intra-Alberta consumers would benefit if NGTL were to collect more of its revenue requirement as an export delivery charge and less as a receipt charge. PICA recommended that the Board direct a change in allocation to receipt charges in a 35 to 40 per cent range, with the remaining 60 to 65 per cent allocated to export delivery.

CANFOR expressed a position very similar to that of PICA and concluded that absent a fully allocated cost of service study detailing the intra-Alberta cost of service, a 35 to 40 per cent cost allocation to the receipt service would seem appropriate and fair.

3.2 ATCO’s Proposal

Views of ATCO

ATCO stated that it had decided to submit an alternative rate design since it did not consider that NGTL’s proposed toll design meaningfully addressed the concerns of intra-Alberta users. In ATCO’s view, receipt point tolling that assumed that all natural gas is delivered to the border regardless of whether it was delivered to an intra-Alberta delivery point would result in rates unduly discriminatory to intra-Alberta users. Furthermore, ATCO believed that NGTL’s proposal would not provide customers with the option to avoid high-cost facilities but still use the mainline.

In response to these concerns, ATCO stated that it had developed an alternative rate design that would introduce distance-sensitive tolling in a manner consistent with sound principles of cost causation and regulatory precedent. In addition, ATCO recommended unbundling of NGTL’s current services in order to introduce competition and greater customer choice and remove the dual toll problem that has faced Alberta pipeline companies for many years. ATCO took the position that the Board should reject the application and direct NGTL to submit an alternative rate design consistent with ATCO’s proposal.

ATCO proposed a zone-based tolling methodology that would create six rate zones (Figure 2). I It based its zone boundaries on NGTL’s design areas with the intent to create zones of comparable geographic size with sufficient natural gas supplies in each zone to support a competitive market for natural gas. ATCO argued that its zonal tolling system would create local markets for natural gas across the province where residential consumers and industrial end-users would benefit from pipeline transportation tolls that reflected their proximity to natural gas resources. ATCO also submitted that using zone-based tolls for natural gas pipelines was common throughout North America and stated that it was unable to identify any unique circumstances associated with the NGTL pipeline system that would fatally flaw a zone-based toll design.

ATCO submitted that its zone-based tolling methodology maintained NGTL's current contractual structure of having separate receipt and delivery service while unbundling NGTL's services to better reflect costs. ATCO explained that under its proposal, all shippers holding receipt service contracts would pay a Receipt Toll and shippers with receipt points on lateral facilities would pay an additional Lateral Toll. ATCO proposed that delivery tolls would be based on a six-zone structure. ATCO indicated that in each zone, there would be both an Intra-Zone Delivery Toll and a Traversing Zone Toll. The Intra-Zone Toll would apply to all transportation volumes delivered within a particular zone. The Traversing Zone Toll would apply to all transportation volumes that crossed a zonal boundary. Export volumes would pay the Traversing Zone Toll in Zone 5, as this zone included the various export delivery points. Shippers buying delivery service would pay the appropriate combination of Traversing Zone and Intra-Zone Delivery charges, depending on the contract path of the transportation service they required. The permissible contract paths would be based on NGTL's determination of how natural gas physically flows on the NGTL system.

ATCO also proposed a backhaul service where NGTL would take natural gas from any of the downstream zones into the upstream zones at no charge. ATCO argued that even if NGTL did not levy a backhaul transportation fee, end-users in upstream zones would normally bear a higher cost of purchasing natural gas than in downstream zones. With respect to storage, ATCO proposed that the NGTL toll for delivery from a zone's inventory to intra-zone natural gas storage facilities should continue to be zero-rated. Upon withdrawal of natural gas from storage, the shipper would pay the appropriate tolls to supply natural gas at the desired delivery point.

ATCO explained that under its zone-based toll design, NGTL's costs would be functionalized into three main categories. The first included costs not dependent upon distance; the second category included mainline costs where distance would be reflected; and the third category reflected lateral costs for those pipeline facilities bringing natural gas to the NGTL mainline. To appropriately allocate the cost for each service, ATCO initially allocated NGTL's Firm Service Revenue Requirement into distance- and nondistance-related cost components. ATCO stated that as a general rule, costs related to ownership, operation, and maintenance of transmission facilities were considered to be distance related. Administrative and general costs and costs related to meter station facilities were considered to be nondistance related. ATCO proposed that NGTL's nondistance-related costs would be recovered through a Receipt Meter Toll.

ATCO submitted that distance-related costs would be recovered through NGTL's mainline and lateral facilities. ATCO stated that it was appropriate to categorize transmission facilities into mainline and lateral functional groupings, since the economic life of a lateral pipeline is less than a mainline facility. Furthermore, small diameter pipelines are characterized by higher unit costs than larger-diameter mainlines. Therefore, treating mainline and lateral facilities separately in the calculation of tolls would be consistent with the principles of cost causation. ATCO indicated that available information was inadequate for it to conduct a segment-by-segment analysis of the NGTL system. Therefore, it assumed that facilities having a diameter of less than 24 inches

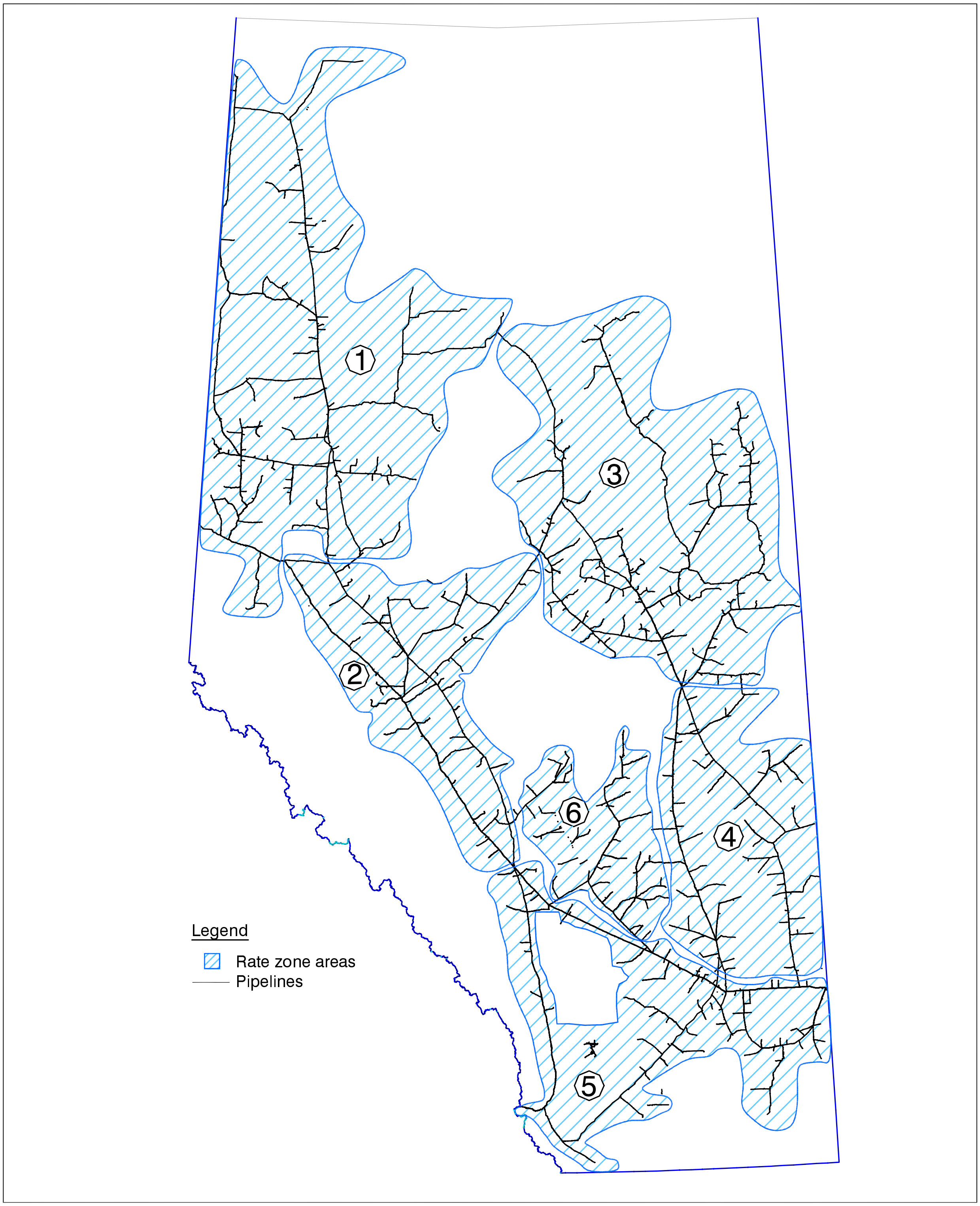

Figure 2. Rate zones as proposed by ATCO
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performed a gathering function, except for the Upstream Bens Lake and Downstream Bens Lake design areas. In these two areas, ATCO assumed that a pipeline with a diameter less than 16 inches was a lateral. Once the mainline and lateral facilities were distinguished, ATCO allocated the distance-related costs to these facilities using the unit cost index produced by NGTL in its application.

ATCO explained that under its proposal NGTL's mainline costs would be allocated to each zone based on the MCF-Mile method. The MCF-Mile method results in all volumes paying the same per-mile of haul rate. For example, natural gas originating in an upstream zone would pay a higher total transportation rate, but only because it travelled a greater distance on the pipeline system. After the mainline costs had been separated into each zone, ATCO indicated that the costs would be appropriately allocated to the Traversing Zone Toll and Intra-Zone Toll. ATCO calculated that the Intra-Zone Delivery charge would reflect 50 per cent of the charge for moving natural gas through that zone on the basis that intra-Alberta deliveries through the zone travel approximately 50 per cent of the distance travelled by natural gas traversing the zone.

ATCO submitted that the most appropriate way to allocate lateral costs would have been to develop a lateral cost of service by zone that considered factors such as vintage and location. However, ATCO indicated that the necessary information to perform such a calculation was not available. Therefore, ATCO assumed, for illustrative purposes, that the toll for lateral receipt service would be the same in all zones.

Based on its cost allocation methodology, ATCO developed the following illustrative rates at a 100 per cent load factor:

	Receipt Service (cents/Mcf)		Delivery Service (cents/Mcf)	
Zone	Receipt Toll	Lateral Toll	Traversing Zone Toll	Intra-Zone Toll
1	1.00	8.50	3.87	1.94
2	1.00	8.50	8.76	4.38
3	1.00	8.50	5.22	2.61
4	1.00	8.50	6.94	3.47
5	1.00	8.50	10.45	2.97
6	1.00	8.50	2.57	1.28

ATCO explained that under its proposal the cost to transport gas from a receipt point on the NGTL mainline in Zone 5 to an export delivery point would be equal to the Zone 5 NIT price plus the Receipt and Traversing Zone Tolls. On the other hand, the cost to transport gas from the market zone (Zone 5) to an intra-Alberta delivery point in Zone 5 would be equal to the Zone 5 NIT price plus the intra-zone toll. ATCO submitted that, as a result, under its proposal the cost of natural gas for intra-Alberta consumers in Zone 5 would be greater than the Zone 5 NIT price by approximately 3 cents/Mcf. ATCO also explained that the overall cost to an ex-Alberta buyer would be less than the current price as the Zone 5 NIT price is approximately 3 cents/Mcf less than the Zone 5 inventory price.

ATCO submitted that under its zone-based toll design, both the producer and the Alberta end-user would benefit. Producers supplying the Alberta end-use market would have higher netbacks, while long-haul shippers would pay tolls in each of the zones that they would like to traverse. On the other hand, intra-Alberta natural gas users would be able to purchase proximal natural gas supplies, if available, at lower tolls than more distant natural gas supplies. Furthermore, under the ATCO rate proposal customers would have the ability to choose the NGTL facilities that they require. Therefore, in ATCO's view, such a rate design methodology would introduce efficiency into the Alberta marketplace, as proper price signals would be reflected in the tolls.

ATCO proposed no changes to NGTL's current requirement that all shippers must balance on a daily basis. ATCO submitted that in order to prevent shippers from "gaming" the zonal rate structure, it would be necessary for shippers to be required to balance on an aggregate basis by zone. However, since transportation tolls are billed monthly, zonal balancing would only need to occur on a monthly basis.

ATCO also proposed that shippers would pay for the fuel required to transport their natural gas to the desired delivery point. Therefore, the fuel requirement for each zone would be determined and recovered when natural gas was delivered within the zone or to the next zone. ATCO indicated that the fuel requirement for intra-zonal deliveries would be one-half the requirements for deliveries to the next zone.

With respect to liquidity and the NIT market, ATCO submitted that the Zone 5 market would be both large and liquid, as it would contain about 90 per cent of NGTL's provincewide market. In ATCO's view, the Zone 5 market would be as large as NGTL's total NIT market in the recent past, a time when all parties agreed that there existed a fully liquid natural gas market. Therefore, rather than reducing liquidity, ATCO believed that its proposal would preserve existing liquidity and at the same time would create regional markets that would benefit Alberta end-users. ATCO also indicated that the more northerly zones would likely trade at a discount against Zone 5 prices in a manner similar to what currently happens for the separate markets that exist now within Alberta. In market equilibrium, the transportation cost differentials would set the NIT price differentials across the six zones. Overall, it was ATCO's view that under its proposal producers would be at worst indifferent, while some may enjoy financial benefit from the tolls and NIT prices in the different zones.

ATCO submitted that under its rate design proposal shippers might be required to manage multiple contracts in various zones. However, ATCO believed that its rate design alternative was no more complex than that of NGTL. ATCO argued that there was nothing in its proposal that was not handled on a daily basis by shippers on pipeline systems across North America. ATCO also indicated that its proposal might create arbitrage opportunities between zones. However, it viewed arbitrage to be desirable, as arbitrage was the outcome of a freely functional market attempting to reduce inefficiency.

ATCO explained that the unbundling of NGTL's services would encourage healthy competition from third-party pipelines that seek to gather natural gas for redelivery into the NGTL mainline or for delivering natural gas off the NGTL system to intra-Alberta markets. ATCO acknowledged that its rate proposal would cause additional risk to NGTL. However, these risks would be consistent with those of a competitive market. In ATCO's view, if certain NGTL facilities are not able to compete, then NGTL should write down its investment in lateral facilities to a competitive level and recover the stranded investment from all shippers through the Receipt Toll.

ATCO submitted that if bypass through zone hopping were to occur under its proposed rate design, NGTL could enter into a load retention service or a point-to-point service arrangement and recover the costs through one of NGTL's service rates. For example, if zone hopping resulted in a change in mainline service volumes, then the delivery service rates would be adjusted. On the other hand, if zone hopping resulted in a change in lateral service volumes, the Lateral Toll in the affected zone should be adjusted. Overall, it was ATCO's view that if NGTL were to offer a load retention service or point-to-point service arrangement due to a bypass of its system, there should not be any shareholder responsibility. ATCO also submitted that despite the claims made by other parties, its rate proposal was not self-serving, as it would not result in a financial benefit for ATCO.

ATCO observed that while its focus was to propose an alternative rate design for the NGTL system, it also believed that most, if not all, of NGTL's proposed terms and conditions of service could be incorporated into ATCO's proposed rate design. For example, term-differentiated rates and conditions under which receipt point transfers were allowed could be equally applicable to its proposed rate design. In ATCO's view, the terms and conditions did not impact the allocation of the overall revenue requirement and therefore could generally be considered in the context of separate negotiations.

Views of NGTL

NGTL submitted that the Board should reject the ATCO rate design alternative. In NGTL's view, the ATCO rate proposal did not satisfy the most important rate design criterion defined by the Industry Process i.e., the requirement to increase accountability without impacting the current liquidity of the Alberta natural gas market and the simplicity and flexibility of the single NIT Pool. NGTL argued that the ATCO rate proposal would, through the development of six zones, create six NIT prices. The end result would be reduced liquidity, unwanted arbitrage opportunities, increased transaction costs, higher administrative burdens, and increased risk for market participants. Therefore, in NGTL's view, the claim that ATCO's rate proposal would preserve and even expand the pooling concept to several regional markets was unsupportable.

NGTL argued that the ATCO rate design created a series of zones and averages that bundled together costs over wide distances and diameter of pipe and therefore would not reflect proper cost causation. For example, NGTL submitted that there was an enormous difference between the unit costs associated with a short 20-inch lateral and a long 6-inch lateral, but this was not accounted for in the ATCO proposal. Therefore, in NGTL's view, ATCO's lateral and mainline rates did not appropriately reflect distance and diameter of pipe in determining costs. NGTL also submitted that ATCO's arbitrary zone boundaries would distort the important relationship between costs and distance. NGTL stated that shippers located within an arbitrary zone boundary would pay an additional toll relative to shippers located a few miles outside the zone boundary and consequently may have an incentive to bypass or zone hop the NGTL system.

NGTL noted that ATCO Pipeline has facilities within each of the proposed zones, providing the ATCO corporation with an opportunity to profit directly from the rate design it had proposed for the NGTL system. Therefore, NGTL did not believe that the ATCO rate proposal would promote healthy competition, as claimed. Instead, it was NGTL's view that it would create and promote bypass opportunities that would benefit ATCO affiliates and disadvantage NGTL and NGTL's customers.

NGTL stated that the ATCO rate proposal would also fragment services in a way that would require multiple contracts in various zones and additional layers of administrative complexity in nominations, scheduling, and gas balancing. Therefore, in NGTL's view, the ATCO zone-based toll methodology would greatly increase the complexity of arranging for and managing transportation on the NGTL system.

NGTL considered that out of the three alternatives to the postage stamp rate design before the Board, the volatility, uncertainty, and nature of the dynamic change under the ATCO proposal would make it most difficult for NGTL to have a fair opportunity to recover its costs. NGTL added that the ATCO rate proposal gave insufficient weight to the key objectives of acceptable rate stability and predictability for customers and revenue stability for the pipeline.

Views of Others

None of the interveners expressed support for the ATCO zone-based toll proposal.

CANFOR and IGCAA submitted that they could not endorse ATCO's proposed rate design as the liquidity and the benefits of the NIT system would be adversely affected. IGCAA added that it was repeatedly told by other parties that if any alternative proposal to NGTL's application were to succeed, it had to keep the NIT market in its current form.

PICA submitted that it could not support the ATCO rate proposal since it would create higher NIT prices and total delivered costs than the NGTL proposal for intra-Alberta customers in Zone 5, where over 50 per cent of intra-Alberta volumes are transacted.

Calgary argued that ATCO's proposed tolling design would complicate deliveries to intra-Alberta markets, since the storage reservoirs would be located in different zones from the major consumption and market areas. It added that the ATCO rate design alternative could create more bypass incentives as producers try to reduce their transportation charges through zone hopping. In Calgary's view, ATCO had failed to demonstrate that a change of this magnitude was necessary or that the impact of such a change would be in the overall public interest.

The CCA and GasAlberta believed that ATCO's zone-based tolling design provided no more relief in the form of lower rates for low load factor intra-Alberta customers than did NGTL's proposed rate design. GasAlberta added that the ATCO multiple toll design would be far more complex than either the status quo or the NGTL proposal. GasAlberta also indicated that if the ATCO rate proposal were approved, the boundary lines should be redrawn so that no local distribution systems were split between zones.

CAPP, Imperial, PanCanadian, and WEG all indicated that the ATCO rate design proposal would reduce the liquidity, price transparency, and the benefits of the single market pool, which in turn could adversely impact the competitiveness of Alberta natural gas in the North American market. These parties also submitted that the ATCO rate proposal failed to meet their needs, as it would unduly complicate the process of managing their transportation needs and substantially alter the simplicity and practicality of the existing system.

It was the position of these parties that because the ATCO proposal would involve multiple zones, a multiplicity of contracts would be required for the various movements of natural gas. These in turn would have to be tracked, dispatched, and accounted for both within separate and across multiple zones. They believed that multiple contracts would cause purchasing options to become more complex. They also indicated that locating major storage facilities in three different zones and ATCO's backhaul provision would add another dimension of contracting, operating, and accounting complexity and cost to the NGTL system. Furthermore, the requirement that fuel be recovered when natural gas is delivered within a zone or across a zone would result in greater complexity than currently exists.

CAPP submitted that over the past two and one-half years it had also considered zonal tolling for the NGTL system. However, CAPP stated that it had quickly become evident, given the nature of the NGTL system, that no grouping of facilities was more supportable than any other grouping and that any zone boundary would be arbitrary and not viable. CAPP indicated that unlike long-distance pipelines that employ geographic zone rates, the NGTL system did not possess distinct geographic segments that directly access multiple supply areas and end-use markets. In CAPP's view, ATCO's proposed zones were arbitrary and therefore would lead to significant zone hopping. CAPP argued that under the ATCO rate proposal, a bypass pipeline could feasibly target NGTL end-users and shippers located close to a zone border. CAPP also argued that the ATCO proposal appeared to be self-serving, as ATCO would be in a position to use its system to bypass portions of the NGTL pipeline, thereby avoiding part of the NGTL tolls.

WEG submitted that it was uncertain whether there would be a three-cent rate reduction for export delivery customers as ATCO had claimed. WEG indicated that even if this rate reduction were to materialize, it would be more than offset by the combination of reallocated fuel costs and additional transaction costs.

3.3 IGCAA's Proposal

Views of IGCAA

IGCAA proposed a rate design alternative in which NGTL would maintain the filed for methodology for ex-Alberta deliveries and allow for a common LDS toll. LDS would be a fixed-rate service available to all Alberta gas shippers to deliver natural gas from any receipt point(s) to any intra-Alberta delivery point. In IGCAA's view, LDS would better reflect the principle of cost causation than either of NGTL's current or proposed tolls for intra-Alberta deliveries. IGCAA added that its rate design alternative would mitigate the disincentive to explore for natural gas in northern Alberta that would be caused under the NGTL proposal. IGCAA stated that under its proposal, intra-Alberta consumers would become a premium market for producers who would otherwise pay the highest tolls to move natural gas to the markets beyond Alberta. Furthermore, the implementation of LDS would help address since the toll for intra-Alberta deliveries has been zero, any misconception that Alberta consumers do not pay their fair share of transportation costs.

IGCAA argued that its distance of haul study, as discussed in Section 3.1.6, was more accurate than that of NGTL. It submitted that the appropriate ratio of distance of haul between intra-Alberta and ex-Alberta deliveries should be 10:1 instead of the 2:1 ratio determined by NGTL. Based on these findings, IGCAA submitted that NGTL's distance of haul methodology and allocation of costs between intra- and ex-Alberta deliveries in its current and proposed rate design was unfair. IGCAA argued that this misallocation of costs had resulted in intra-Alberta shippers and consumers subsidizing ex-Alberta shippers. IGCAA estimated that this subsidy had reached more than $67 million per year and indicated that if the NGTL rate design proposal were approved, there could be additional costs due to matters such as bypass of the NGTL's system by intra-Alberta consumers.

IGCAA stated that it recognized that the distance/diameter aspect of the NGTL proposal was one way of achieving cost accountability for export service and did not oppose that aspect of the proposed rate design. However, IGCAA noted that intra-Alberta service realities were so different from those of export that it was totally inappropriate as a basis for the intra-Alberta toll design. Therefore, its objective in the proceedings was to promote an NGTL service offering that would better reflect the proximity of Alberta consumers to Alberta's natural gas reserves.

Based on its distance of haul study, IGCAA determined that the average toll to transport natural gas to an intra-Alberta delivery point would be 3 cents/Mcf (at 100 per cent load factor). However, IGCAA requested that the LDS rate be set at 6 cents/Mcf (at 100 per cent load factor). IGCAA submitted that setting the LDS at 6 cents/Mcf was based on an element of judgement in the same way that NGTL determined the tolls for Interruptible Receipt and Delivery rates. The judgement factors that IGCAA considered included:

- the value of access to the large pool of natural gas available behind NGTL,

- an LDS toll level similar to the cost NGTL attributed as being fair for southern producers to access any intra-Alberta delivery point in the province, and

- the fact that the 3 cents/Mcf represented the cost of an average haul; the longest haul to an Alberta delivery point is approximately double the average haul.

IGCAA asserted that it would still want the LDS concept implemented even if the Board were to determine a different cost allocation and value for LDS than had been proposed.

Under its rate design proposal, IGCAA submitted that intra-Alberta deliveries could be met by an LDS, by a Firm Transportation Receipt (FT-R) contract that could be converted to an LDS, or through continued purchase of natural gas using the NIT Pool. IGCAA stated that it expected that LDS, since it was proposed based on a 100 per cent load factor, would be used primarily by shippers to transport base-load natural gas requirements to Alberta consumers. Low load factor customers would be expected to purchase their natural gas from the NIT Pool, which would be delivered utilizing conventional FT-R service.

In IGCAA's view, most of the LDS would initially be transported using FT-R contracts, as it would take some time for intra-Alberta consumers to adjust to the LDS. IGCAA also submitted that shippers holding FT-R contracts would under its proposal have the right to convert any portion of the contract to LDS for a minimum period of one month during the term of the contract. At the end of the term, the LDS contract volumes would revert back to the full FT-R contract. IGCAA proposed that the tolls for LDS volumes transported under FT-R contracts would be 115 per cent of the LDS toll calculated at 100 per cent load factor, or 7 cents/Mcf. IGCAA also indicated that a shipper moving natural gas under an LDS contract would be able to execute NIT at an additional charge of 115 per cent of the FT-R toll less the LDS toll and multiplied by the volumes transacted through the NIT. IGCAA also proposed that the minimum term for an LDS contract would be one year. LDS shippers would be allowed to change receipt points under the same terms and conditions proposed for FT-R contracts, and term differentiated tolling would apply to LDS as currently proposed for FT-R service by NGTL.

IGCAA acknowledged that LDS and the conversion of FT-R to LDS would result in slightly lower volumes being traded on the Alberta NIT market. However, IGCAA did not believe that such a small reduction in volumes would have any appreciable affect on the flexibility, operation, or liquidity of the market. It also recognized various parties' concerns with the ability of NGTL to track volumes of natural gas under LDS. IGCAA stated that NGTL could track the natural gas used under LDS with an officer's certificate, similar to the current LRS volumes. Initially, IGCAA had also proposed that LDS would not be available for storage. However, after examining the submissions of several parties, IGCAA stated that it now believed that LDS could become available for storage and these volumes could also be tracked using an officer's certificate.

In response to the concerns of various parties with the impact of IGCAA's rate design alternative on FT-R and Firm Transportation Demand (FT-D) rates, IGCAA submitted that the impact would depend on the volumes contracted under LDS. Based on the assumption that 70 per cent of firm deliveries to Alberta delivery points would be transported under LDS through conversions of FT-R service, IGCAA determined that the FT-R tolls at each receipt point and the uniform FT-D tolls would each be increased by 0.43 cents/Mcf.

Views of NGTL

NGTL submitted that the Board should reject the IGCAA rate design proposal. In NGTL's view, the IGCAA proposal did not satisfy the most important rate design criteria defined by the Industry Process, i.e., the requirement to increase cost accountability without impacting the current liquidity of the Alberta natural gas market and the simplicity and flexibility of the single NIT Pool. NGTL believed that under IGCAA's rate proposal, natural gas contracted to the LDS service would not be available to the NIT Pool and any inventory transfer would be transacted outside of the pool. Therefore, NGTL believed that the IGCAA rate design alternative would effectively create a system with two pools, which would reduce the current liquidity of the NIT Pool.

NGTL noted that while IGCAA was requesting a service in which natural gas could be accessed from any receipt point, IGCAA's distance of haul methodology assumed that natural gas serving an intra-Alberta delivery point always comes from the nearest upstream receipt point. In order to achieve an appropriate level of cost accountability, NGTL argued that the LDS service should restrict qualifying receipts to natural gas supply from the nearest upstream receipt points.

NGTL submitted that IGCAA's distance of haul was arbitrary, simplistic, and an obvious attempt to shift costs from one customer group to another, as it discriminated against export customers in favour of intra-Alberta deliveries. NGTL added that the IGCAA rate proposal ignored the important cost factors of scale/diameter and scope/network economies and assumed distance to be the sole determinant of bundled pipeline costs for intra-Alberta deliveries. Therefore, in NGTL's view, IGCAA's alternative rate design did not reflect the rate design principle of cost causation.

NGTL observed that while the proposed IGCAA toll is quite simple to understand, if it were to be accepted some complications could arise with respect to the NIT Pool and the operation of the NGTL system. In NGTL's view, as the LDS is neither a receipt nor a delivery service, the company, in order to accommodate the offering of a service such as the proposed LDS, would have to modify its existing contracting, account balancing, and inventory transfer systems and would also have to implement natural gas tracking.

Views of Others

Natural gas producers and export shippers generally expressed concerns similar to NGTL's with regard to IGCAA's proposed rate design. CAPP, Imperial, PanCanadian, and WEG agreed with NGTL that the IGCAA LDS proposal would be unfair and did not appropriately reflect cost causation. These parties also agreed with NGTL that the IGCAA alternative tolling methodology would result in a reduction of significant volumes of natural gas from the NIT Pool, which in turn would affect its liquidity, transparency, and the price of natural gas. These parties also believed that the IGCAA proposal would result in increased complexity, as it would require the tracking of natural gas at the time of nomination. CAPP, Imperial, PanCanadian, and WEG added that the IGCAA rate design proposal would result in an artificial inducement to sell natural gas into the intra-Alberta market that would subsidize intra-Alberta prices. CAPP added that while intra-Alberta consumers are important and valued customers of the producing industry, producers are not in the business of subsidizing natural gas consumers, just as gas consumers are not in the habit of subsidizing producers. WEG also submitted that with the anticipated increase in natural gas use in future oil sands projects, the impact on FT-R and FT-D rates would be more significant than IGCAA had suggested.

Phillips submitted that if the Board were to institute the rate design methodology proposed by NGTL, it would support the inclusion of IGCAA's proposed LDS. In its view as a primarily northern producer, LDS would provide it with the opportunity to mitigate the impact of a significant increase in tolls that it expected would occur under the NGTL proposal. Phillips added that the LDS could also help to eliminate the risk of inefficient bypass of the NGTL system by natural gas consumed in northern Alberta.

The intra-Alberta consumers had varying positions with respect to IGGAA's rate design option. ATCO, Calgary, CCA, and GasAlberta submitted that they opposed the IGCAA alternative. ATCO and Calgary believed that IGCAA did not succeed in overcoming the underlying fundamental problems they had with the NGTL proposal. On the other hand, CCA and GasAlberta believed that IGCAA's proposed alternative would provide no relief in the form of lower NGTL rates to low load factor intra-Alberta customers. GasAlberta added that the evidence with respect to converting FT-R to LDS for low load factors was not convincing. It also submitted that the proposal would have been more attractive if it provided LDS on a commodity charge basis, either as a stand-alone service or on conversion basis, and if LDS were available for deliveries made into storage.

CANFOR and PICA both submitted that the IGCAA rate design alternative was at least directionally more appropriate when compared to the other rate design alternatives. These parties believed that IGCAA's LDS would provide additional flexibility to high-cost producers, making it possible to serve the needs of small to medium load factor customers. These parties also submitted that a daily conversion option for LDS would offer even more flexibility for intra-Alberta consumers. PICA added that the daily FT-R conversion should be set at a premium of 130 per cent of the LDS rate and the restriction of deliveries to storage using LDS should be removed. It also submitted that the size of the NIT Pool might be reduced under the IGCAA proposal but would not be unduly impaired and that the Board should not be deterred by these concerns.

Although Alberta Treaty Eight submitted that it favoured the existing postage stamp rate methodology, it stated that it could support IGCAA's proposal if it could be made sufficiently robust and flexible to provide alternatives for aboriginal communities, for both low load factor customers as well as high load factor projects such as cogeneration.

3.4 Maintenance of Postage Stamp

Views of Phillips

Phillips submitted that the Board should maintain the existing postage stamp rate design methodology, including the availability of load retention service to address any threats of bypass to the NGTL system. Phillips argued that on the basis of NGTL's postage stamp rate methodology, it had recently invested significantly, in the development of natural gas reserves in northern Alberta. In Phillips' view, it would be categorically unjust for the Board to approve NGTL's application, as this would result in a drastic change in the Applicant's pipeline rate structure. The company stated that it had conservatively estimated that the impact of NGTL's proposed rate design on Phillips would be in the neighbourhood of $10 million over the Transition Period.

Phillips noted that the earlier evidence submitted by CAPP and NGTL in support of postage stamp rates during the GRA was still relevant and that, in fact, no evidence had been submitted in this proceeding that would justify a change to NGTL's rate design. In Phillips' view, the continued maintenance of the postage stamp rate methodology would be consistent with the physical and operational integration of the NGTL system. Furthermore, the postage stamp rate methodology remains consistent with Alberta's economic and resource interests. It added that the existence of the postage stamp rate design has enhanced the ability of Alberta producers to compete in the North American natural gas market by placing all Alberta natural gas on an equal footing in relation to the market.

Views of NGTL

NGTL submitted that in recent years producing companies have increased their scrutiny of natural gas transportation costs in an effort to increase the competitiveness of the Western Canadian Sedimentary Basin (WCSB). It explained that following the Board's GRA decision, a multitude of bypass pipeline proposals threatened the viability of NGTL's system and the postage stamp rate design. These bypasses of NGTL's system were commercially viable to the proponents when compared against its existing postage stamp rate design. Furthermore, none of these bypass proponents was prepared to suspend its projects pending resolution of a new NGTL toll design. Therefore, in NGTL's view, the fact that customers had been prepared to proceed with bypass alternatives signalled that a form of pricing more reflective of costs might now be more appropriate than the postage stamp rate design. With respect to the concerns raised by Phillips, NGTL agreed that over the last fifteen years billions of dollars had been invested in natural gas development and transmission infrastructure. However, it did not agree with Phillips that this investment was directly related to NGTL's postage stamp rate design.

Views of Others

Alberta Treaty Eight and Calgary submitted that they supported the existing postage stamp rate methodology for the NGTL system.

CAPP submitted that its principal interest in the proceeding related to the need to maintain the competitive position of the WCSB in the North American natural gas market. In order to achieve this objective, it believed that a move away from postage stamp to a toll design that better aligned rates with cost causation was necessary. CAPP added that since the GRA there has been a need for another rate design to address competitive alternatives that had been coming to fruition as a result of the postage stamp rate design, and this led to the acceptance by its members of the need for change. CAPP stated that a change to a receipt point specific tolling methodology would limit the cross-subsidization among shippers and reduce the artificial economies that had led to a number of bypass proposals under the postage stamp rate methodology.

Views of the Board

The Board was presented with four rate design options for the NGTL system:

- preservation of the existing postage stamp rates,
- Receipt Point Specific Rates, as proposed by NGTL,
- a Zone-Based rate design, including unbundling of services, as proposed by ATCO, and
- introduction of an LDS for a local rate, as proposed by IGCAA.

With regards to the first alternative, that is maintaining the current postage stamp rates, the Board notes the strong support expressed at the hearing by both producers and intra-Alberta consumers in favour of a change to the current rate structure. Other than Phillips and Alberta Treaty Eight, the majority of participants did not support the continuation of the postage stamp methodology. The Board notes that ProGas and SEPAC objected to the proposed terms and conditions of service but not to a rate design change.

The Board believes that the present examination of the appropriateness of NGTL's existing postage stamp rate design reflects a growing concern about natural gas transportation costs in a very competitive market. In the few years since the GRA, the evidence is clear that NGTL has faced significant challenges. Competition in natural gas transportation has intensified and competing alternate pipelines have forced NGTL to mitigate the potential erosion of its customer base by providing alternatives to postage stamp tolling. Such bypass threats and the introduction of load retention services and other discounting approaches exercised by NGTL to address them have, however, increased the risk of future higher rates for remaining customers. This, in turn, could lead to further competitive pressures. Therefore both the pipeline and its customers are interested in ensuring that the toll design does not exacerbate this situation.

The Board notes that increased competition in the continental natural gas market appears to have caused the majority of producers and many intra-Alberta consumers to support the concept of increased cost accountability, apparently in the hope that this would lead to more cost-effective and efficient transportation services. The Board believes that while the postage stamp tolling methodology is relatively simple to apply and administer, it does not address certain aspects of current industry concerns, such as cost causation, as well as other models. Bypass proposals, emerging competition in the natural gas transportation business, tighter natural gas supply, the desire to properly reflect the cost of providing service, and the need to cut waste and to introduce discipline on requests by shippers are all concerns of the pipeline and shippers alike. Addressing all of these is now considered to be necessary for Alberta to effectively compete in the continental natural gas market.

The Board recognizes that by its nature the postage stamp rate design results in cross-subsidization of longer and more remote area hauls by the shorter hauls that are close to delivery point. The rolled-in nature of the postage stamp rates can potentially also result in less than economic pipeline tie-ins, as all costs are paid collectively by customers. As a policy tool, the postage stamp tolling methodology has been, by extending the transportation network throughout the province, effective in enhancing the development of natural gas reserves. Given the significant expansion of the NGTL system over the past twenty years, the Board believes that to a great extent this goal has been accomplished. Therefore, it is now appropriate to determine whether other public interest issues should be considered paramount in the design of the NGTL tolls. Having considered the evidence and all of the issues discussed above, the Board concludes that the adoption of an alternative to the existing postage stamp rate structure is now in Alberta's public interest.

As noted above, three alternatives to the postage stamp rate design were proposed at the hearing. In assessing which, if any, of the proposals would be acceptable, the Board must have regard to the results expected to be achieved while minimizing negative effects. The Board must also have regard to sound rate-making principles. The Board notes that the proponents of the three rate design alternatives generally considered cost causation, fairness, and simplicity to be the main rate-making principles upon which each based its respective proposal. The Board agrees with the proponents and adds that in the Board's view the basic attributes of a proper rate design should include:

- **Efficiency—**The rate design should promote innovation and respond economically to changing market dynamics. This would include cost causation, since if resources are used efficiently, proper price signals are established. This, in turn, discourages the wasteful use of services.

- **Effectiveness—**The total revenue requirement of the utility must be met without any socially undesirable expansion of the rate base. As a regulated utility, NGTL operates on a cost of service basis. Therefore, there should be a fair and reasonable balance between the interests of the NGTL shareholders and those of its customers.

- **Fairness—**Appropriate apportionment of the total cost of service among the different rate-payers is required to avoid arbitrariness and attain equity.

- **Simplicity, certainty, understandability, public acceptability, and ease of administration—** These attributes are important in judging how practical the proposed rate design is and how easy it would be to apply.

- **Freedom from controversy regarding proper interpretation—**The rules must be clear and equally applicable.

In carrying out its evaluation of the three options, the Board notes that while all claim to adhere to same set of rate design criteria, each has a different objective. NGTL's stated goal is to attain increased cost accountability while maintaining market flexibility and the liquidity afforded through a single market concept for natural gas in Alberta. ATCO's desire, in addition to properly reflecting the cost of providing service, is for a rate design that provides customers with a choice on whether to utilize mainline facilities and bypass the small-diameter, high-cost facilities. IGCAA's objective is to redesign the rates payable by domestic natural gas users to better reflect their proximity to the resource and so reduce the risk of unfair subsidization of ex-Alberta shippers.

The NGTL Proposal

With respect to NGTL's proposed rate design, the Board notes that the proposal appears to have retained a number of simplifying factors currently embedded in the postage stamp rate structure. These include, for example, the approach to splitting of revenue requirement between receipt and delivery services, keeping the method of determining delivery charges intact, and the use of system average costs (now averaged for each diameter across the system). This lower level of complexity should generally also result in lower associated business risks, higher levels of certainty, and subsequently more stable rates for NGTL's customers.

The Board also finds that NGTL's proposal should continue to preserve the single market concept, referred to as the NIT Pool, which the Board believes is a positive and significant attribute of the current system. The evidence is clear that the NIT, a product of collaborative efforts between NGTL and its customers, is considered to be beneficial by both producers and consumers. The overwhelming support by hearing participants for the preservation of the single market concept suggests that a rate design that preserves the much-desired market transparency, liquidity, simplicity, and flexibility of NIT would also have a higher level of public acceptability.

The Board accepts that NGTL's proposed receipt point specific rates appropriately account for the significant cost factors of pipeline diameter and distance. The Board considers the NGTL approach in using distance and pipe diameter as a proxy for cost incurred by customers using the facilities to be reasonable. While accounting for pipeline vintage, geographical locations, and actual costs of building these facilities would have been a more accurate measure, the Board notes that such would add to the complexity of the rate calculations and could result in additional costs to the system. The Board accepts NGTL's argument that having been subject to the postage stamp methodology for so long, the company simply does not have a sufficiently detailed account of the actual cost of individual pieces of equipment on the system to carry out such an analysis effectively.

The Board is mindful not to impose unnecessary costs on NGTL and believes that any perceived value from a detailed cost analysis has to be weighed against its usefulness and benefit to all involved. The unbundling of NGTL's costs could require significant effort, time, and resources. Even if all specific costs could be measured, they may be too complex to incorporate effectively into a practical rate design. Moreover, no evidence was submitted as to the benefits of a detailed accounting of costs against the potential rate differentials obtained. The Board also believes that using system average costs and distance/diameter as a proxy rather than actual production costs would lead to rates that generally reflect the cost of providing service at stable and predictable levels from both the customers' and the utility's point of view.

The Board acknowledges that since system average costs are utilized, the NGTL proposal may not completely satisfy the cost causation criteria. However, it is moving in this direction. The Board also believes that NGTL and its customers could if it was felt to be beneficial also further fine tune the proposed rate structure in the future.

The Board agrees with the proposed incorporation of a transition period to mitigate the impact of moving away from the postage stamp rate structure. Moving to a new rate structure over two to four years should allow sufficient time for companies that might experience rate increases to adjust their operations accordingly. The Board also supports the applied-for price floor and ceiling over the Transition Period. The Board considers the proposed Transition Period to be a positive attribute that should allow for more stability and predictability in the new rate design.

Based on the results provided at the hearing, the Board is prepared to accept that on average intra-Alberta volumes travel 43 to 47 per cent of the distance travelled by ex-Alberta volumes. The Board continues to believe that intra-Alberta customers enjoy benefits not afforded to ex-Alberta shippers. For example, while ex-Alberta delivery contracts impose a contractual obligation to deliver at specified delivery points, intra-Alberta shippers do not have similar obligations. The Board also believes that intra-Alberta consumers have benefitted indirectly from the expansion of the NGTL system over the years. The Board therefore finds that using this distance as a proxy to set the intra-Alberta charge at 50 per cent of the ex-Alberta charge is reasonable. The Board considers this ratio as a proxy for rate setting and would not find it advisable, for rate stability reasons, for the cost allocation to vary on an annual basis to reflect the actual ratio as demonstrated by annual distance of haul study. The Board, therefore, concludes that the 2:1 ratio as a proxy for the cost allocation between intra- and ex-Alberta services remains appropriate. However, should significant variations in the distance of haul ratio occur in the future, the Board will consider changes in the allocation of costs between these two services.

The Board rejects the suggestion made at the hearing by some parties that since intra-Alberta customers do not pay delivery charges, they are in some manner subsidized by ex-Alberta customers. The Board believes that intra-Alberta delivery charges are already addressed in the receipt charges. Unless future cost of service studies convince the Board otherwise, it believes that under the NGTL proposal, intra-Alberta customers will continue to pay their fair share.

The Board concludes that receipt point specific rates as proposed by NGTL satisfy the attributes of a proper rate design. The Board believes that under its proposal NGTL will meet its revenue requirement without any significant undesirable affects on the rate base. Furthermore, incorporation of a transition period along with maintaining some attributes of the current system will also contribute positively to rate stability. The Board notes that the majority of hearing participants did not object in principle to the applied-for rate design, which suggests that it is reasonably well understood and acceptable to the affected parties. The Board also believes that the proposal is relatively simple to implement once the initial rates at the different receipt points are calculated and downstream facilities identified. Consequently, it is expected to be relatively simple to administer. The new tolling methodology should also be relatively free from controversy since the rate at each receipt point is solely dependent on distance and downstream facilities to the border delivery points. NGTL's proposal also appears to fairly allocate costs among the customer classes. Finally, the Board finds that the proposed rate design satisfies the efficiency requirement of sound rate making, since in general it adequately reflects the cost of providing service.

With respect to NGTL's request to eliminate the commodity charge, the Board accepts NGTL's submission that this would further simplify the proposed rate design. The Board notes that no objections were raised with respect to this issue. Furthermore, the Board agrees with NGTL that given that the commodity charge represents only 1.6 per cent of total revenue requirement, customers will not be materially affected by its elimination.

The ATCO Proposal

The Board agrees that ATCO's proposed rate structure better reflects cost causation than the current system. Unfortunately, in order to do this, the proposal requires the arbitrary determination of zone boundaries. The Board believes that a rate design based on different zones, while it may create other forms of market efficiencies, does create more potential opportunities for bypass than under the NGTL proposal. The Board notes that in fact it was the ongoing risk of commercially viable but economically inefficient bypass that led NGTL and its customers to re-evaluate the use of postage stamp rates.

Much of the criticism of the ATCO proposal raised by hearing participants was based on its complexity relative to the other alternatives. Furthermore, the evidence suggested that there was a significant risk that six distinct markets could arise replacing the single market concept and adding further complexity to natural gas transactions. ATCO suggested that its proposal was preferable to the NGTL proposal since it provided customers with greater choice. The Board, notes, however, that none of the participants at the hearing, many of whom were predicted by

ATCO to ultimately benefit from its proposal, considered this division of the Alberta market to be sufficiently advantageous to cause them to support the ATCO proposal. Even export shippers, whom ATCO predicted would pay less than they do currently, determined that the proposed reduction in costs did not outweigh the risks associated with increased complexity.

The Board believes that ATCO's proposed rate design could potentially also result in stranded facilities, thereby increasing business risk to NGTL. This in turn could lead to higher rates to remaining shippers. The Board also believes that producers could face higher risk as well, in the form of reduced market transparency and liquidity and increased transactional complexities. Furthermore, it is not obvious to the Board how intra-Alberta customers would benefit from ATCO's proposal. For example, in Zone 5 (southeastern Alberta), where more than half of the intra-Alberta volume is transacted, the proposed rate structure would lead to intra-Alberta customers paying 3 cents/Mcf more for their natural gas than they do currently.

As to the question of fair allocation of costs between intra- and ex-Alberta shippers, the Board does not believe that the ATCO proposal offers any advantages over either the current tariff or the NGTL proposal. ATCO testified at the hearing that it believed that the current cost allocation is likely fair and the resulting cost allocation under the ATCO proposal does not appear to be significantly different from the current level, NGTL is proposing to maintain.

A positive aspect of ATCO's proposal is its attempt to separate lateral from mainline charges. The Board agrees that such an approach would better encourage competition in the provision of lateral services and would provide customers with the choice of only accessing mainline facilities. However, the Board believes that the impact of ATCO's proposal on market liquidity and ease of transactions outweighs such a benefit.

The Board concludes that ATCO's zonal tolling methodology satisfies some attributes of rate design principles, such as efficiency, revenue recovery, and fairness. It fails, however, to satisfy other important attributes, such as simplicity, general acceptability, and freedom from controversy, particularly with the determination of zone boundaries.

The IGCAA Proposal

The Board notes that of the three new alternative rate structures, only IGCAA's LDS proposal suggests changes solely to the intra-Alberta service. The LDS would be a uniform rate based on a distance of haul analysis that assumes that natural gas delivered to intra-Alberta customers originates from the nearest receipt point upstream of each delivery location. IGCAA did not express opposition to the NGTL proposal as long as its LDS proposal was also adopted.

The Board understands IGCAA's position to be based on two premises. First, a receipt charge for intra-Alberta service that is based on distance from the receipt point to a border delivery point is unfair to customers receiving natural gas within the province. Second, the current rate structure with only a receipt charge and a zero delivery component, gives the false impression that intra-Alberta customers pay less than their fair share of the cost of providing service. The Board is sympathetic to both of these concerns. However, the Board does not believe that IGCAA's proposed solution would provide its members the relief they are seeking and at the same time adhere to proper rate design principles.

The Board notes that the proposed LDS is based on a distance of haul assumption that intra-Alberta delivery points are satisfied from the nearest upstream receipt point. In the Board's view, however, this does not realistically reflect what might be expected to occur. For example, the Board notes that more than 50 per cent of intra-Alberta consumption occurs in the southeastern part of the province close to border delivery points. The Board saw no evidence that would suggest that this natural gas was all delivered into the NGTL system from receipt points immediately upstream of the point of delivery. The relatively large volumes of shrinkage natural gas required by the straddle plants located effectively on the Alberta border are unlikely to have been received from the nearest receipt points. In the Board's view, the premise upon which IGCAA based its modified alternative does not adequately conform to the cost causation principle.

The Board notes that while IGCAA proposed that cost allocation between intra- and ex-Alberta services should reflect the principles underpinning its distance of haul methodology, IGCAA later modified its proposal to better reflect the value added by the fact that an intra-Alberta delivery point could receive natural gas from any receipt point at a uniform LDS rate. As a result, the Board believes that the principle upon which IGCAA has proposed to set the cost allocation between the two services is relatively arbitrary, at least in comparison with the NGTL proposal, and could therefore result in rates that are neither equitable nor free from controversy.

The Board notes that under the NGTL proposal intra-Alberta customers could contract for their natural gas at any receipt point, including those with locational advantages resulting from the proposed receipt point specific tolling methodology. Under an LDS concept, intra-Alberta customers are advantaged only if receipt holders are willing to enter into an agreement whereby any transportation cost savings would be shared with customers.

The Board also does not believe that imposing an artificial LDS rate is in the public interest. Intra-Alberta customers already have the advantage of being close to natural gas reserves, and the Board believes that security of supply is best afforded through contractual arrangements in a freely functioning market. The argument that IGCAA (or other intra-Alberta customers) could share economic rent with shippers whose natural gas production is behind receipt points with the highest receipt charge may not hold true if shippers have commitments for their natural gas elsewhere or are not willing to sell at below the market price. Moreover, given the current cost allocation between intra- and ex-Alberta services, even if an LDS were to be implemented, the LDS rate would not be substantially different from the average receipt charge applicable under NGTL's proposal for intra-Alberta service.

As to IGCAA's second concern, which is the false perception as to the fairness of the intra-Alberta contribution to NGTL's cost of providing the service, the Board has already confirmed its belief that intra-Alberta consumers do pay their fair share through the receipt charge. The Board is, however, also of the view that NGTL should continue to endeavour to eliminate this misconception and to ensure that Alberta services are priced in a manner that is both cost reflective and perceived to be cost reflective.

In summary, the Board believes that the receipt point specific tolling as proposed by NGTL represents a reasonable balance of acceptable attributes of sound rate making and will be in the public interest. The new rate design is directionally positive in that it is more reflective of the cost of providing service. The proposed Transition Period should also provide sufficient time for NGTL's stakeholders to adjust to the new rates without facing a substantial rate shock. The Board believes that the new rate design will help to discourage uneconomic resource developments, reduce cross-subsidisation, and minimize commercially viable but economically inefficient bypass and should therefore lead to lower rates in the long run.

While the Board is prepared to accept the NGTL proposal, it does intend to observe how the intra-Alberta rates materialize over the Initial Period. Over this period, intra-Alberta customers will also have a chance to test the new rate design and assess its impact on their business. If at the end of the Initial Period, there are still legitimate concerns that need to be resolved, the Board is prepared to address these concerns.

4 NEW SERVICES

Views of NGTL

In its application, NGTL proposed that in the future it would provide new services at its own risk and reward, subject to a disclosure mechanism and the inclusion of rights for customers to complain to the EUB. The "New Services" would be offered outside the utility revenue requirement. NGTL submitted that the proposal, which was a result of its discussions with industry, was to be initially applicable for an interim period of 24 months (the Initial Period).

NGTL stated that under its proposal, any New Services issued during this period would be incremental to the existing services defined in NGTL's tariff and to the three existing pilot services[4] currently being tested by NGTL. NGTL believed that the New Services provision was an opportunity for it to offer, in a timely fashion, services not presently available that may be desired by one group of shippers and not by others. NGTL also described it as an opportunity for producers to more effectively manage their transportation needs.

The MOU stipulated that the reasonableness of any New Services would be determined by a process that included full disclosure to NGTL's customers and to the Tolls, Tariffs and Procedures Committee (the TTP), with a provision for complaint to the EUB. NGTL observed that the MOU established a set of principles and processes designed to ensure that any new services offered would have no adverse effect on existing services. Furthermore, appropriate and fair compensation would be allocated to the utility revenue requirement for any benefits provided from services or facilities already included in the rate base.

NGTL submitted that the New Services proposal was needed to meet the evolving needs of its customers in a timely fashion. It noted that the existing process for instituting new services, through achieving consensus by members of the TTP prior to seeking EUB approval, was slow and inefficient, often because TTP members had different competitive positions. This, NGTL submitted, further frustrated the process of instituting changes or new offerings.

NGTL added that having the ability to provide new services on a competitive rather than a regulated basis was also a critical component of the general consensus it had reached with industry. NGTL noted that it had not proposed any new services in its application, and urged the Board to dismiss the SEPAC and ProGas requests that a number of services, which were either not raised or not accepted during the Industry Process, be included as existing services.

NGTL stated that it appreciated that certain parties had concerns with the New Services proposal and for that reason significant effort was invested during the Industry Process to ensure that these concerns have been adequately addressed. It noted that appropriate controls and processes had been put in place as a result of such concerns.

[4] Current pilot services being tested are Storage Interruptible Prioritization Pilot, Alternate Access of Firm Service (Export Delivery), and the Pilot Procedures for Supply to Demand balancing (effective April 1, 1996).

NGTL indicated that New Services would not be created through either the reduction or replacement of any of the attributes of existing services. Enhancement to existing services would not be considered as new services unless the effect of the enhancement materially changed existing services. NGTL stressed that each new service would be fully disclosed to its customers and the TTP at the time of offering. Such disclosure would include:

- a description of the terms and conditions and the price of the service;
- confirmation and evidence that the new service would not adversely impact existing services or shippers; and
- a description of the calculated value, along with supporting assessment of any existing facilities or services included in the rate base but used to provide the new service. The value of such facilities or services was proposed to be determined by either fair market value, existing costs of the facilities or services used, or any other appropriate methodology.

NGTL submitted that the New Services provision was only agreed to for the Initial Period. If on the basis of actual experience the concept proved to be unworkable, it would be revoked by the end of the 24-month period. Notwithstanding the fact that the concept would only be applicable over the Initial Period, NGTL explained that any new service could have a contractual term extending beyond the Initial Period. In that case, the revenue and costs associated with the service would be treated as if incurred prior to expiration of the Initial Period.

NGTL proposed that the EUB regulate New Services on a complaint basis. NGTL was unsure whether legislative changes were required for the EUB to accomplish this. If they were, NGTL asked that its proposal be approved subject to such changes. If a complaint were filed with the EUB, NGTL submitted that NGTL would have the responsibility to provide the information necessary for a complete assessment of the new service. If the Board were to uphold a complaint alleging that a new service had resulted in a materially adverse impact to an existing service, NGTL would credit the revenue requirement with all the revenues received from the New Service from the date it was first provided. All costs associated with the new service would also be borne by NGTL's shareholders. If, on the other hand, a complaint were upheld regarding how NGTL had accounted for the benefit of any facilities or services included in the rate base, NGTL submitted that an adjustment would be made to the revenue requirement in accordance with Board's determination. It added that all costs incurred by NGTL in dealing with a complaint before the Board respecting any new service would be the responsibility of its shareholders, whereas the costs of other parties would be assigned against the regulated portion of NGTL's revenue requirement.

Views of SEPAC

SEPAC submitted that the merger of TCPL and NGTL could lead to a significant increase in market power. Consequently, SEPAC maintained that continued full regulation of NGTL was necessary, in order to ensure cost-effective and open-access transportation within the province. It objected to separation of the New Services from NGTL's rate base and revenue requirement, since this would create distinct regulated and nonregulated revenue streams, with an added burden on customers to monitor the nonregulated activities. SEPAC submitted that it was not only unnecessary but imprudent to provide an incentive to a regulated entity to create nonregulated revenue that could not otherwise be generated without the existence of the utility rate base.

SEPAC considered that the absence of a proper definition of a new service reflected another significant weakness of the proposal. SEPAC also stated that it believed that NGTL was already providing operating services to a nonregulated affiliate with full benefits accruing to the cost of service. At the same time, the operating service drew upon utility assets and personnel, but this was not expressed in NGTL’s tariff. SEPAC expressed concern that if the New Services proposal were approved, this and similar services would result in revenues generated from utility assets flowing to NGTL’s shareholders.

While agreeing that NGTL did not cite any specific new services, SEPAC submitted that potential new services could have a profound effect on the operation and economic viability of the NGTL system, as well as the viability of the producing sector. SEPAC gave interconnection with Alliance as an example of a potential new service utilizing NGTL’s existing infrastructure, yet with benefits accruing to the account of its shareholders. This potential service, SEPAC submitted, was also vital to producers to sustain continued exploration and development activities, since access to surplus transportation on NGTL at a reasonable rate would be essential to maximize producer netbacks. In SEPAC’s view, interconnection with Alliance should not be offered as a new service.

SEPAC submitted that the New Services proposal was one of the reasons why SEPAC did not sign the MOU even though it was party to the negotiations. It found the proposal that the New Services would not be prefiled with the EUB to be unacceptable. SEPAC added that after reviewing the material submitted in this proceeding, it now took the position that no new services should be offered outside the revenue requirement, regardless of whether they are filed for approval of the Board.

SEPAC did not believe that recourse to a complaint mechanism was more efficient than the current regulatory process. It submitted that even full disclosure to the TTP and the existence of a Code of Conduct ensuring the arm’s-length separation of NGTL and any affiliates participating in the New Service could not be more effective than full regulation. Furthermore, in its view, regulation by complaint would lead to less accountability by NGTL. SEPAC observed that NGTL had been regulated by a complaint mechanism in the past but that had proven to be costly, lengthy, and unsatisfactory.

SEPAC contended that if NGTL’s objective were not to establish an nonregulated affiliate with utility rate base and services, but rather to expedite changes to existing services and offering of new services, then it would support such an objective. It also added that NGTL could achieve the desired expediency by improvement to and streamlining of the current process. SEPAC suggested, for example, the appointment of an EUB staff member to adjudicate any disputes from a technical point of view. If there were disagreement with the adjudication, a dissenting notice could be sent to the Board for automatic review by a Board member. However, it was SEPAC’s expectation that any major changes to rates, tolls, and tariffs would continue to be assessed through a public hearing process.

SEPAC added that there were no provisions in the Gas Utilities Act that would allow NGTL to offer a new service subject only to a complaint procedure. Any changes to the rates, tolls, or charges have to be approved by the Board. Accordingly, SEPAC submitted that NGTL's New Services proposal would require legislative changes.

Views of ProGas

ProGas submitted that it was not appropriate for a cost of service pipeline, such as NGTL, to be given the ability to keep revenues generated for its sole account. In ProGas's view, the concept of risk/reward balancing could be addressed more appropriately in the context of the renegotiations of the CEIS. ProGas added that the New Services proposal represented an incentive to NGTL but without the company assuming any greater risk in return. ProGas submitted that NGTL could become more competitive by concentrating on becoming more efficient and reducing costs while improving the quality of service, rather than seeking the right to create New Services to the sole benefit of its shareholders.

ProGas stated that the proposal failed to clearly define the nature of a new service. It expressed concern that types of services that ProGas proposed, specifically secondary access for firm receipt service, IT priority for firm shippers, and demand charge relief, would be characterized by NGTL as new services.

ProGas concluded that if the New Services proposal were approved, NGTL should not be allowed to exercise its sole discretion in determining what would qualify as an enhancement to an existing service or a new service. Neither should NGTL be entitled to decide the appropriate methodology for crediting the revenue requirement as a result of the new service.

Views of Others

CAPP stated that its support for the New Services proposal was conditional on the application being viewed as a package deal and not as an individual element of the MOU. PanCanadian and Suncor echoed CAPP's position. Imperial added that while it supported the MOU, it had reservations about the New Services provisions and indicated that it may not be willing to support these services beyond the Initial Period.

Similar to ProGas, PanAlberta expressed concern about the lack of detail in the MOU regarding the terms and the definition of a new service. It noted that what constitutes a new service and the associated crediting of the revenue requirement would be a matter that may have to be determined by the Board through a complaint mechanism, which in the past had proven to be unsatisfactory.

GasAlberta argued that the New Services proposal should not be approved. Whether approved in part or as a whole, only services or facilities related to new receipt and delivery laterals should qualify for new service arrangements and furthermore must be built on the basis of a customer contribution to NGTL.

Calgary submitted that what NGTL proposed for New Services may become a template for other utilities. It expressed a fundamental concern with the concept of nonregulated services being provided within a regulated utility. Calgary interpreted NGTL's position to mean that if it were required to respond to changing market conditions, it should be allowed to earn a return in addition to what was currently approved. In Calgary's view, this approach to utility service offerings should be rejected as a matter of principle.

Calgary concurred with SEPAC regarding required legislative changes, since, in its view, the New Services proposal would breach Section 36.1 of the Gas Utilities Act. It also expressed concerns similar to those of ProGas and PanAlberta relating to setting of the appropriate value of regulated assets used in providing the new services if the proposal were approved by the Board.

Views of the Board

The Board notes that NGTL stated that it considered its New Services proposal as an essential aspect of providing it with the necessary tools to compete. However, at the same time, the company did not provide examples of what such new services might entail or with whom it might be competing in the provision of potential new services. The absence of any concrete examples makes it difficult for the Board to adequately assess the anticipated scope of NGTL's proposal. In particular, the Board is concerned with how distinctions would continue to be made between new and currently offered services. The Board also notes that NGTL's definition of new services is not confined to just competitive services but includes all services, other than the three pilot projects it listed, not currently in its tariff. Therefore, it does appear that the range of services that could ultimately be placed within New Services may be substantive.

NGTL conceded that it was not aware of any other fully regulated pipeline that treats services in the manner proposed in this application. Therefore, there was no precedent available nor was it obvious to the Board that any regulated competitors of NGTL can offer services along the same principle as being proposed. In addition, the Board notes that NGTL's proposal does not contemplate providing access to third parties who could also provide similar nonregulated services. As a result, NGTL under the New Services proposal could potentially have significant market power allowing it to influence both what new services it offers and at what prices.

The Board understands that NGTL's New Services offering is, in part, in response to its own frustration with the current process used to implement new services. The Board agrees that the current practice of seeking complete consensus of customers of diverse needs and interest is time consuming and can also lead to suboptimal results. The Board is not convinced, however, that regulation by complaint as proposed by NGTL, would necessarily be either a more cost- or time-efficient alternative. It is also not clear whether the Board has the legislated authority to allow the testing of new services on a complaint basis only.

The Board notes that NGTL has proposed to implement the New Services proposal for an interim period of two years, presumably to allow parties to better understand its implications. It would appear possible that following the two-year period if the ongoing provision of nonregulated services were rejected, NGTL might still expect at least some nonutility revenue streams to continue. This could result in a significant increase in the complexity of regulating the NGTL system.

It is also not obvious to the Board what impact the provision of nonregulated new services may have on NGTL’s risk profile or what the impact might be on the return to equity on the regulated portion of its investment. Under the proposal, NGTL would have both regulated and nonregulated revenue streams but presumably would raise capital from the same equity markets.

Finally, the New Services proposal clearly provides a disincentive for the provision of changes to or improvements in existing services. The Board has and continues to encourage NGTL to offer a range of services that would enhance the position of both NGTL and its customers. The Board is not, in this case, convinced that sufficient effort has been made by the parties to improve the existing process. Rather it would appear to the Board that in fashioning the Agreement with CAPP, the provision of New Services became simply one component of a series of complex tradeoffs between the parties. Nor is the Board convinced by the evidence provided in this hearing that the future ability to provide non utility services is critical to NGTL’s competitive position in the marketplace.

Given the above and the evidence submitted, the Board concludes that the New Services proposal as filed would be contrary to the public interest and it is therefore denied.

The Board expects NGTL to work with its stakeholders to examine the process of how it might more effectively offer new services to its customers in the future. If such services cannot be implemented in a timely fashion and streamlining the current process is unsuccessful, then the Board would encourage NGTL to bring its case forward to the Board for its consideration. The Board believes that an argument can be made for allowing NGTL to implement new services for the few who may require them, provided that other customers are not disadvantaged. However, the Board cannot accept that NGTL be given a preauthorization to implement any new service, subject only to complaint, that makes use of regulated assets even if at its shareholders’ own risk and reward. If confronted in the future with a situation where a new service might only be desired by few, NGTL should be able to apply to the Board with full disclosure. The Board could then, based on the merit of the specific application, determine whether a new service could be offered outside of the rate base.

5 NEW FACILITY CONSTRUCTION AND PRICING

Views of NGTL

NGTL stated that the Agreement envisioned a significant change with respect to the provision of new facilities. NGTL stated its intention that after a short transition period the construction, operation, and ownership of new Alberta receipt laterals upstream and new Alberta delivery laterals downstream of the existing system would no longer be part of its rate base. The costs of such construction would now be the responsibility of the party or parties requiring new facilities. NGTL stated that the objectives of this change were twofold: first, to introduce competition for the provision of new receipt and delivery laterals. Second, to increase cost accountability of those requesting the new facilities.

NGTL submitted that under its proposal a potential customer requiring a new facility would propose connection to its system after consideration of all competitive options. NGTL stated that its affiliates would not be excluded from also offering connection services on a negotiated market-based-arrangement. It asserted that in order to ensure fair competition, only information available in the public domain would be provided by NGTL to its affiliates wishing to offer these services.

NGTL indicated that the new facilities construction proposal was a concession on its part. It would have preferred to maintain new receipts and laterals in the rate base, but the proposal resulted from the negotiations with CAPP and the bilateral discussions with various stakeholders.

NGTL submitted that while no precise definition of the difference between laterals and mainlines was reached in its negotiations with industry associations. In general a new connection of 12 inches or less in diameter and distinctly associated with only a limited number of customers would likely be considered a lateral. Customers would be accountable for all costs associated with these connections. Conversely, facilities triggered to meet the aggregate forecast of more than one customer would fall into the mainline category. NGTL stated that if there were disagreements over whether a particular facility was as mainline or lateral, the matter would be referred to the Facility Liaison Committee (FLC) for resolution. Failing agreement, parties might seek the Board's ruling.

NGTL stated that under its proposal all meter stations and tie-ins into the system would continue to be provided, owned, and operated by NGTL in accordance with the current practice. In determining the best location for tie-in into the NGTL system, a lowest cost of service evaluation would be conducted, taking into account the costs borne by the customer requesting the service, as well as all costs expected to be caused on the NGTL system as a result of this request. Disputes over the best location for the tie-in would be referred to the FLC for resolution. If the result was unsatisfactory to either party or others who might be affected by it, the dispute would then be referred to the EUB.

NGTL observed that a gas transportation agreement, with a primary and a secondary term, would still be required from a customer requesting new facility connections. The primary term of the agreement would reflect recovery of the costs of new facilities, including meter stations, tie-ins, and directly attributable downstream lateral looping. The primary term would be determined, similar to the current practice, in accordance with NGTL's Economic Criteria for Determining Contractual Obligations. The secondary term of three years would reflect recovery of costs associated with downstream mainline facilities.

NGTL stated that if connecting to its system would require mainline looping or extension to meet the aggregate firm service requirement of all customers served by the mainline, NGTL would build the mainline and roll those costs into the rate base. All receipt contracts would have three-year secondary terms to provide accountability for downstream mainline costs.

If access to an existing lateral provided the least-cost connection for a new receipt service at a specific point, NGTL stated that it would provide the necessary access and if required would also add capacity to the lateral. The cost of the capacity addition would be rolled into the rate base. The primary term of the transportation contract would reflect the cost of capacity addition plus the measurement and tie-in costs. A primary term of ten years would still be required for export delivery services requiring construction of new facilities.

NGTL submitted that contrary to SEPAC's contention, the proposal for construction of new facilities would not lead to degradation and ultimate discontinuance of NGTL's published Annual Plan. In NGTL's view, it would continue to expand the system to meet aggregate customers' needs. Moreover, NGTL noted that its planning process was not based on point specific plans of producers but rather on a forecast prepared through collaboration with NGTL's customers through the FLC. NGTL did not believe that approval of its proposal would lead to any changes in this well-established process.

NGTL also refuted SEPAC's claim that implementing the proposed process for future construction of new facilities would be unduly discriminatory. It submitted that under the proposed process customers would have a financial interest in selecting projects that would minimize the overall required facilities. In contrast, a customer under the current practice had little incentive to select the overall most cost-effective alternative to connect to NGTL, since the cost of the connection was rolled into the rate base and paid by all customers. NGTL concluded that its proposal was not discriminatory but rather intended to increase cost accountability and efficiency in new connections.

Views of Others

CAPP supported NGTL's proposal to open up competition in the construction of new receipt and delivery lateral facilities. According to CAPP, this would lead to lower costs and reduce cross-subsidization on the NGTL system. CAPP added that while it supported the principle of fair competition in the laterals business, it recognized that further refinement of some details of the proposal would have to be addressed through the FLC. For example, CAPP noted that criteria to be used to distinguish mainlines from laterals still needed to be developed. CAPP's position was that these issues would be addressed on an ongoing basis by the FLC, with recourse to the EUB if necessary. It also submitted a full and acceptable Code of Conduct among NGTL, TCPL, and their affiliates was necessary prior to implementation of this portion of the Agreement, as this would ensure that NGTL's affiliates were acting at arm's length from the regulated entity.

Clan Duncan also expressed support for competition in the construction of laterals. However, it submitted that if an agreement on a Code of Conduct could not be reached, NGTL's affiliates should be prohibited from competing in the construction of connecting facilities. It added that the Board should assume full remedial powers that are both probationary and compensatory in nature if inappropriate behaviour is determined between NGTL and its nonregulated affiliates. According to Clan Duncan, the Board must have full disciplinary powers and the ability to impose sanctions, including the award of monetary compensation for any demonstrated violation of the Code of Conduct. CAPP, on the other hand, submitted that the imposition of a financial penalty in the Code of Conduct was not a key point, as it would be difficult to define. Nonetheless, CAPP believed that if there is a substantial breach to the code, it would not want to preclude the option of asking the Board for a penalty.

IGCAA expressed concern that there was no definition in the application or in NGTL's Annual Plan as to what constituted a mainline and a lateral. It also indicated that there were significant issues associated with the conditions under which a lateral could become a mainline. Nonetheless, IGCAA submitted that it would support NGTL's proposal to allow competition in the construction of laterals if there were a fair definition regarding what constituted a mainline versus a lateral.

Alberta Treaty Eight, CCA, ProGas, and SEPAC submitted that they did not support NGTL's proposal that new lateral construction be separated from the rate base. IGCAA, ProGas, and SEPAC expressed concern that there was no clear definition as to what constituted a mainline or a lateral. SEPAC added that, given the integrated nature of NGTL's system, there could not be a clear distinction between the transmission and gathering functions.

Alberta Treaty Eight, ProGas, and SEPAC contended that NGTL's proposal was unfair, as shippers requesting new laterals would pay incrementally for this service but would continue to contribute to the costs associated with existing laterals on the NGTL system. In the views of ProGas and SEPAC, this would amount to a cross-subsidization by future customers. SEPAC added that the additional costs of new laterals in combination with distance-based tolls could prohibit future exploration and development activity in the northern areas of the province.

ProGas and SEPAC also argued that an affiliate of NGTL that constructed laterals would have a strategic advantage over external contractors. They asserted that an NGTL affiliate would have access to but not be limited to utility-subsidized engineers and design staff, economies of scale by purchasing pipe with the regulated entity, information regarding confidential reserves, and tax benefits. ProGas and SEPAC testified that even if a Code of Conduct were implemented among NGTL, TCPL, and their affiliates, this would not alleviate their concerns.

SEPAC also submitted that NGTL's proposal would be unduly discriminatory. It explained that if a plant operator requested additional capacity on an existing lateral, then the costs would be rolled into the NGTL system. On the other hand, if a second producer wanted to tie in its natural gas to NGTL from the same pool, the cost of the second lateral would be incremental. In SEPAC's view, since the latter producer's costs would be higher, it would also be less competitive.

SEPAC added that NGTL's current practice with respect to the construction of new laterals is also more efficient, safe, and effective in comparison to the proposed policy. It noted, for example, that under the proposed policy if sour gas was accidentally allowed to move through a producer-owned lateral to the NGTL system, the monitoring equipment at the NGTL inlet could shut the inlet involved. This could create the need to have another line for return of the gas to the plant for further processing. Therefore, under NGTL's proposal there could be an unnecessary duplication of facilities. SEPAC also submitted that although NGTL would continue gathering data and information relating to reserves and the preparation of its Annual Plan, the purpose would no longer relate to the construction of laterals, but only to the appropriate sizing of mainline facilities. Therefore, in SEPAC's view, the NGTL proposal would adversely affect NGTL's ability to prudently size expansions and would lead to a degradation and ultimate discontinuation of its published Annual Plan.

According to SEPAC, NGTL had always adopted a competitive bid process for the construction of its laterals and producers had always had the right to build their own laterals. Therefore, in SEPAC's view, it was unclear how NGTL's proposal would introduce greater competition. Nonetheless, SEPAC proposed that if NGTL wanted to create greater competition, then it would prefer that once the lateral was constructed it be turned over to NGTL at the constructed cost and added to the rate base.

GasAlberta requested the Board to direct that new facilities be built on the basis of a customer contribution to NGTL. GasAlberta explained that this would result in the ownership title of the lateral remaining with NGTL and such an arrangement would ensure that GasAlberta customers would have access to service from those new laterals.

Views of the Board

The Board believes that continuing to roll the cost of new receipt and delivery laterals into the rate base is potentially contrary to the desirable objective of discouraging uneconomic expansion. There is little accountability under a rate design where all system users pay equally for all additional expansions. The Board believes that the proposal to move the construction of new laterals into a competitive market, provided the remaining unresolved concerns can be adequately addressed, could resolve many of these issues. The Board, therefore, accepts that the proposed changes could achieve the two objectives set out by NGTL, first, by increasing the accountability of those who request the facilities and, second, by ensuring that new lateral construction is cost competitive.

The Board is encouraged by the fact that a lowest-cost of service evaluation would be conducted by NGTL. in determining the best location for tie-in into the NGTL system. The Board believes that these evaluations should result in customers having a greater financial interest in selecting the most cost effective alternatives, which in turn should minimize the overall required size and number of facilities, resulting in greater efficiencies, cost savings, and reductions in cross-subsidization.

The Board does not agree with the submission made by several parties that the implementation of this proposal would be unfair or discriminatory. The Board acknowledges that shippers requesting new laterals would pay incrementally for this service and also continue to contribute to the costs associated with the downstream facilities. However, all shippers situated at same receipt point would continue to pay the same rate under similar terms and conditions. Since shippers that require additional services are not located similarly they can be treated differently. Therefore, the Board is of the view that the proposed new facility construction is neither discriminatory nor unfair.

The Board is aware that certain of NGTL's affiliates may wish to participate in the construction of new laterals. While the Board fully endorses introduction of competition in the construction of receipt and delivery laterals, it remains concerned that a truly level playing field exist and that NGTL's affiliates do not have an unfair competitive advantage due to affiliate relationship. The Board notes the strong pressure from a number of regulated utilities for permission to allow nominally arm's-length affiliates to enter into competitive marketplaces. In the Board's mind, however, the risk of unfair competition by non-regulated affiliates of a regulated utility is a significant and ongoing concern. One important step in alleviating the concerns associated with such transactions is ensuring transparency in the dealings between regulated and nonregulated affiliates. Such transactions must not only be at arms length but must also be perceived to be at arms length.

In this instance, the Board believes that any competition for the right to construct new laterals cannot be open and fair unless, at a minimum, a proper Code of Conduct is implemented among NGTL, TCPL, and their affiliates. The Board notes the wide agreement among many interveners, including producers, competitors, and intra-Alberta customers, that approval of the new facility proposal must be conditional upon the implementation of a proper Code of Conduct. In the Board's view, a Code of Conduct would be a significant step towards levelling the playing field, as it would help ensure that NGTL affiliates are acting at arm's length from the regulated entity.

The Board therefore finds that at a minimum a Code of Conduct acceptable to the Board must be in place before it would be prepared to consider allowing NGTL affiliates to compete for new lateral construction. In the Board's view, this may alleviate the concerns of producers, competitors and intra-Alberta consumers, as it would help ensure that there are no perceived advantages between NGTL, TCPL and their affiliates. If there were breaches to the Code of Conduct, the Board will be willing to address any disputes and, if necessary, consider the impact on NGTL's shareholders on a case-by-case basis.

The Board also recognizes the concerns of various parties regarding the lack of a clear distinction between a mainline and a lateral. However, the Board accepts as reasonable NGTL's submission that in general new connections of 12 inches or less in diameter distinctly associated with one or a few customers would normally be considered laterals, while facilities required to meet the aggregate forecast of more than one customer would normally be classified as mainlines. The Board also notes that NGTL has instituted a system to address disagreements in interpretation of the new rules. The Board endorses the proposal of having the matter referred to the FLC for resolution if there are disagreements over whether a particular facility should be designated as a mainline or a lateral. Failing a satisfactory resolution, any affected party could present its case to the Board.

The Board also accepts NGTL's suggestion that new receipt and delivery facilities be included into its rate base using the existing process if such facilities can be in service within the first four months after implementation of the Board's decision.

6 TERMS AND CONDITIONS OF SERVICE

6.1 Existing Services Renamed

Views of NGTL

NGTL submitted that under its application existing services would remain bundled. However, it would like to rename or recategorize them to better identify and reflect the service being provided. NGTL explained that firm service would be more clearly categorized as receipt, export delivery, and intra-Alberta delivery contracts. It added that intra-Alberta deliveries would be classified as a firm service, while interruptible service would be divided into several categories for administrative purposes but not for cost allocation or tolling purposes. NGTL explained that the renaming or recategorizing of existing services would not in any way change the treatment of their priorities or prices other than as specifically identified in the MOU (i.e. firm transportation receipt and interruptible transportation receipt services). The following table illustrates NGTL's proposed name changes for existing services:

Existing Service	Renamed Service
1) FS (Firm Service)	a) FT-R (Firm Transportation Receipt)
	b) FT-D (Firm Transportation Delivery)
2) IT-2 (Interruptible Service)	a) FT-A (Firm Transportation Alberta)
	b) FT-X (Firm Transportation Extraction)
	c) IT-R (Interruptible – Receipt)
	d) IT-D (Interruptible – Delivery)
	e) IT – S (Interruptible – Storage)
3) LRS (Load Retention Service)	LRS (Load Retention Service)
	LRS-2 (Load Retention Service)
4) STFS (Short Term Firm Service)	STFT (Short Term Firm Transportation Delivery)
5) OS-3 (Other Service)	FCS (Facility Connection Service)
6) OS (Other Service)	OS (Other Service)
7) T-4 (Unconnected Export Service)	T-4 (Unconnected Export Service)

Views of the Board

The Board notes that the proposed renaming of existing services was not opposed by any of the parties. The Board is prepared to accept the proposed new names, including changing the intra-Alberta service to a firm service.

6.2 Term Differentiation

Views of NGTL

NGTL proposed term-differentiated tolls to allow for increased customer choice and contractual flexibility. According to NGTL, term-differentiated tolling would recognize the market value inherent in different service attributes and, in particular, the length-of-contract term. NGTL stated that customers would be given a choice of selecting a mix of longer and shorter terms for service under rate schedule FT-R at different rates during the Initial Period. NGTL proposed that the price for FT-R service would vary as follows:

- 105 per cent of the Firm Service Receipt Point Specific Price for contract terms of one year but less than three years;

- 100 per cent of the Firm Service Receipt Point Specific Price for contract terms of three years, but less than five years;

- 95 per cent of the Firm Service Receipt Point Specific Price for contract terms of five years or more.

NGTL also submitted that Interruptible Receipt (IT-R) contracts would be priced at 115 per cent of the Firm Service Receipt Point Specific Price, while Interruptible Delivery (IT-D) contracts would maintain a price of 110 per cent of the FT-D price. NGTL explained that these rates were determined during the Industry Process, where it was agreed that it would be appropriate if the relative prices of interruptible service remained at a price that was 10 per cent above the comparable firm service price. Therefore, since the shortest firm service receipt contract is a one-year term with a 105 per cent price, the appropriate IT-R contract would be 115 per cent of the Firm Service Receipt Point Specific Price for a 3-year firm receipt contract. On the other hand, since there is no term-differentiated tolling on the export delivery side, the appropriate IT-D contract would be 110 per cent above the FT-D. NGTL also submitted that the floor price for bidding on Short-Term Firm Service (STFT) would remain unchanged at 135 per cent of the FT-D price.

In NGTL’s view, providing shippers with an incentive to sign longer contractual commitments would assure longer-term utilization of its facilities and would provide a more stable environment for planning the development of its system in an orderly, efficient, and cost-effective manner. NGTL argued that if customers choose not to sign long-term contracts, then these customers should be required to pay a premium for the flexibility afforded by shorter contractual commitments.

Views of the Board

The Board is of the view that since different term contracts have different values to the parties entering into them, it would be proper to price these contracts accordingly. The Board believes that it is important in an environment where competition is emerging that NGTL has the ability to offer its customers a mix of long- and short-term contracts at term-differentiated rates. In the Board’s view, this should result in more diverse customer choice and increased accountability for both the pipeline and the customers requesting service. The Board is unsure whether the current proposed risks and benefits related to the various terms are sufficiently substantive to provide the market with strong enough signals to achieve these goals completely. However, the Board notes that NGTL’s proposed rate differentials for the different terms is for the Initial Period. This should be sufficient for the company to determine whether its objectives are being met and to design any needed improvements.

The Board therefore approves in principle the concept of term-differentiated rates. The Board also approves the applied for rate/term relationship for the Initial Period. The Board notes that there was no objection to NGTL’s request that the rate for interruptible receipt service be changed from the current 110 per cent of the firm receipt price to 115 per cent of the Firm

Service Receipt Point Specific Price for a three-year firm receipt contract. Accordingly, the Board approves this request.

6.3 Revenue Collar

Views of NGTL

In order to limit the potential benefit and risk to NGTL and its customers over the Initial Period, NGTL proposed the implementation of an annual Revenue Collar of plus or minus $5 million. It explained that the impact on its revenues that would result from term-differentiated pricing and IT-R, IT-D, and STFT premiums would be subject to the revenue collar and would apply to revenue associated with

- the revenue surplus resulting from the term premiums for FT-R;
- the revenue shortfall resulting from the term discounts to FT-R;
- 50 per cent of the revenues resulting from the premiums for IT-R;
- 50 per cent of the revenues resulting from the premiums for IT-D; and
- 50 per cent of the revenues resulting from the premiums for STFT.

According to NGTL, if the sum of the above revenues resulted in revenues that were in excess of the revenue collar, then the excess revenues would be refunded to its customers. On the other hand, NGTL indicated that if the sum of the above revenues resulted in a loss that was in excess of the revenue collar, then the excess loss would also be recovered from its customers. Losses or gains within the collar would be the responsibility of NGTL's shareholders.

NGTL noted that there were two processes available for parties to terminate the proposed revenue sharing mechanism during the Initial Period. NGTL explained the process could be initiated if either the CAPP Board of Governors or a customer that holds a firm service contract on NGTL and is not a member of CAPP was of the opinion that

- NGTL was behaving in a manner aimed primarily at increasing its revenues from its interruptible service and STFT offerings, and
- such behaviour has resulted or is likely to result in a material detriment to NGTL's customers generally— for example, an inability of customers to obtain timely firm transportation services from NGTL in sufficient volumes.

NGTL stated that it believed that financial incentives would influence the behaviour of any company, including a regulated utility, to improve its service offerings. It stated that its proposition was supported by the fact that many performance-based regulation agreements are currently evolving throughout the regulated industries. NGTL also indicated that a revenue collar was determined to be necessary during the Initial Period to address the uncertainty associated with how customers would react to the increased choices for contract term. In its view, the revenue collar would limit both NGTL's and its customers' exposure to this uncertainty.

Views of Others

In ProGas's view, the need for NGTL's proposed revenue sharing and revenue collar was unclear. ProGas argued that it could see no behaviour (e.g., increased system efficiency) being offered in return for sharing of premium revenues. It added that NGTL did not appear to be assuming any greater risk in return for receiving these incentives and it did not believe that NGTL's proposed return and revenue sharing were proportional to the level of risk it would assume. ProGas believed that the only way NGTL could lose under the current proposal was if all of its shippers elected terms of five or more years, a scenario it found highly unlikely. According to ProGas, NGTL's risk/reward collar would not accomplish anything other than a chance for NGTL to generate an additional $5 million in revenue for its shareholders. Therefore, it was of the view that if NGTL would like more opportunities to keep revenues for its own account, then it must clearly establish why it should be entitled to do so and must assume a proportionate level of risk.

Views of the Board

The Board believes that the revenue collar proposal could result in a somewhat arbitrary balance between the needs of the company and its customers. In this case the Board is willing to accept that the proposed revenue collar will likely strike a reasonable balance between these two positions. The Board does not accept that the proposal provides an unreasonable opportunity for the company to generate windfall revenues, and furthermore, the Board believes that the proposal offers customers some protection from unexpected imbalances in the proposed rate design. Therefore, the Board is prepared to accept in principle the proposed revenue collar including the revenue sharing concept as described above. The Board also accepts the applied-for annual revenue collar of plus or minus $5 million to be applicable for the Initial Period.

6.4 Renewal of Service

Views of NGTL

NGTL submitted that the required prior notice for the renewal of all firm service would be increased from six to twelve months. It explained that failure to provide notice of the renewal of service (or portion thereof) would result in the service expiring on the service termination date. The minimum renewal period would be one year.

In NGTL's view, increasing the notice of renewal from six to twelve months would encourage the prudent development of its pipeline system, as it would be able to obtain timely information about the level of service required by its customers. NGTL added that to ensure that service is available to customers when needed, it must determine facility requirements well in advance, procure the associated pipe and equipment, and then construct the facilities. NGTL acknowledged that extending the renewal period from six to twelve months could pose a difficulty for some customers with short planning horizons.

NGTL added that customers who hold service under rate schedule FT-R with terms and conditions of three years or more, would be offered an incentive to provide 24 months' prior notice of their intention of whether or not they would renew all or a portion of their service. According to NGTL, customers providing 24 month' prior notice would continue to be charged the term-differentiated price applicable to that contract for the balance of the term. If they failed to provide this notice, the Firm Service Receipt Point rate for the applicable receipt point would be the one-year term-differentiated price for the remaining 24 months of the contract term.

Views of Others

CAPP agreed with NGTL's view that by increasing the renewal period from six to twelve months NGTL would obtain contract information earlier than under the current practice and that this would enhance its system planning.

ProGas and SEPAC submitted that the current renewal notice period of six months was still appropriate for firm receipt service. They believed that the current notice of renewal represented an appropriate balance between the desire for NGTL to have timely information upon which to design its system and a shipper's ability to manage its transportation portfolio effectively. ProGas and SEPAC maintained that producers, due to their capital planning cycle, generally commit to the expenditures required to maintain deliverability on an annual basis. The approval of such expenditures normally occurs a few months before a new fiscal year. SEPAC added that this is especially the case in the northern areas of the province, where drilling access is limited to the winter period. Therefore, ProGas and SEPAC both submitted that it would be difficult to meet a one-year renewal notice period and their concerns and problems would be exacerbated if they had to provide information 24 months before the expiry of a contract.

ProGas believed that an incentive for a renewal notice of 24 months, as proposed by NGTL would render its term-differentiated pricing unnecessary or inappropriate. It argued that while it saw some merit in allowing longer term commitments to receive some sort of discount, the 5 per cent discount being proposed by NGTL would be essentially meaningless in the context of the proposed renewal incentive. ProGas explained that most shippers would not know the extent of their transportation requirements over the next 24 months. Therefore, the discount being offered by NGTL was insignificant and would not likely induce shippers to contract for longer terms.

SEPAC also submitted that NGTL's proposal for notice of renewal would likely result in producers contracting for extra capacity in order to obtain sufficient transportation. In its view, this could have an undesirable effect on producers in the northern regions since NGTL may, as a result, construct facilities larger than required. SEPAC also indicated that if shippers held an excess of NGTL service, there would be a larger expense deduction for the associated tolls, which could in turn lower royalty payments, resulting in an adverse impact on the public interest.

SEPAC submitted that it would prefer that if a shipper did not serve 12 months' notice prior to the end of a contract term, the shipper would commence paying 107.5 per cent of the three-year rate until 6 months prior to the end of the contract term. According to SEPAC, if the shipper served notice 6 months prior to contract termination, it would then return to paying the appropriate toll. On the other hand, if the shipper did not serve notice within the 6 months remaining in a contract, it would continue to pay the 107.5 per cent of the three-year rate premium until the contract expired, and at the same time would have no renewal rights.

Views of the Board

The Board determined in *Decision U96055* that a notice of renewal of 6 months was appropriate. However, when this finding was made there were pipeline capacity constraints to ex-Alberta markets leaving the province with excess supply of natural gas. It is the Board's view that in a market of increased demand and tighter supply, one would expect that contract terms would tend to be longer. Given the expected additional export pipeline capacity, an increase in the notice of renewal from 6 to 12 months appears to be reasonable. The Board believes that a longer contract renewal notice period will also increase the accountability of NGTL customers. Requiring that customers increase their notice of renewal from 6 to 12 months will enable NGTL to more accurately predict the demand for firm service, thereby diminishing the risk of overbuilding the system. Therefore, the Board is prepared to accept an increase in the notice of renewal for firm service contracts from 6 to 12 months. The Board also considers that a minimum renewal period of one year continues to be reasonable.

While the Board agrees with NGTL that the notice of renewal should be increased, the Board does not accept NGTL's proposal that 24 months' notice of renewal would need to be provided in order to maintain the contracted term-differentiated rate. In the Board's view, such a proposal provides no benefit for producers and could in fact force producers to sign shorter- rather than longer-term contracts, since long-term contracts would potentially have a greater risk. The Board believes that this is contrary to NGTL's stated objectives of a longer-term commitment to its system and greater cost accountability.

The Board also does not accept SEPAC's proposal that if a shipper did not serve 12 months' notice prior to the end of the contract term, the shipper would commence paying 107.5 per cent of the three-year rate until 6 months prior to the end of the contract term. While customers will have an incentive to provide 12 months' notice, the minimum notice of renewal that would be required would remain at 6 months. This, in the Board's view, is not an appropriate amount of time for NGTL's planning purposes.

The Board finds that a 12-month renewal notice period would provide an appropriate balance between NGTL's needs for its system planning and shippers' needs to assess production and marketing decisions. As this change can only apply to existing firm service contracts with an excess of 12 months currently remaining in their term and to new contracts, the Board directs that a shipper that has contracted for firm service should have the right to renew such service by giving NGTL not less than 12 months' notice prior to the expiry date of the contract where such service expires on or after March 1, 2001.

6.5 Receipt Transfers and Term Swaps

Views of NGTL

NGTL proposed that the existing conditions for transfers and swaps for firm receipt service be changed to increase cost accountability for receipt constructed facilities. A customer not within the Primary Term of its FT-R contract would continue to be permitted to transfer or swap its firm contracted volume from one receipt point to another within the same NGTL Project Area if the conditions set out in the applicable rate schedule were satisfied. NGTL defined the Primary Term to be the number of years of service under a schedule of service under rate schedule FT-R required for the cumulative present value revenue to equal or exceed the cumulative present value cost of service.

NGTL identified the Project Areas as the Peace River Project Area, the North and East Project Area, and the Mainline Project Area (Figure 3). It added that in the case of a transfer, capacity would also have to be available at the desired receipt point. NGTL indicated that the price for service at the new receipt point for the balance of the term of the contract would be the term-differentiated price based on the original term of the contract at the new receipt point.

NGTL submitted that a customer not within the Primary Term of its FT-R contract and that wanted to transfer its firm contracted volume from one receipt point to another receipt point that not within the same NGTL Project Area would be permitted to do so if

- capacity was available at the desired receipt point,
- the conditions set out in the applicable rate schedule were satisfied, and
- the customer agreed to amend its contract for service at the new receipt point to add an additional three-year Secondary Term.

Alternatively, a customer not within the Primary Term of its FT-R contact that wanted to term swap firm contract volumes from one receipt point to another receipt point that was not within the same project area would be permitted to do so if

- the conditions set out in the rate schedule were satisfied, and
- the remaining term on either of its swapped contracts was less than 36 months and the customer agreed to amend each of its swapped receipt contracts to add an additional three-year Secondary Term.

NGTL noted that in the case of either a receipt transfer or term swap, the price for the balance of the term, including the new Secondary Term of the contract, would be the applicable term-differentiated price at the new receipt point for the balance of the term. In NGTL's view, imposing a Secondary Term when a customer transfers or term swaps service to another Project Area would increase accountability for the costs of downstream mainline facilities that are required to provide the service from that new receipt location.

NGTL also confirmed that currently FT-R contracts within their Primary Term cannot be transferred or term swapped.

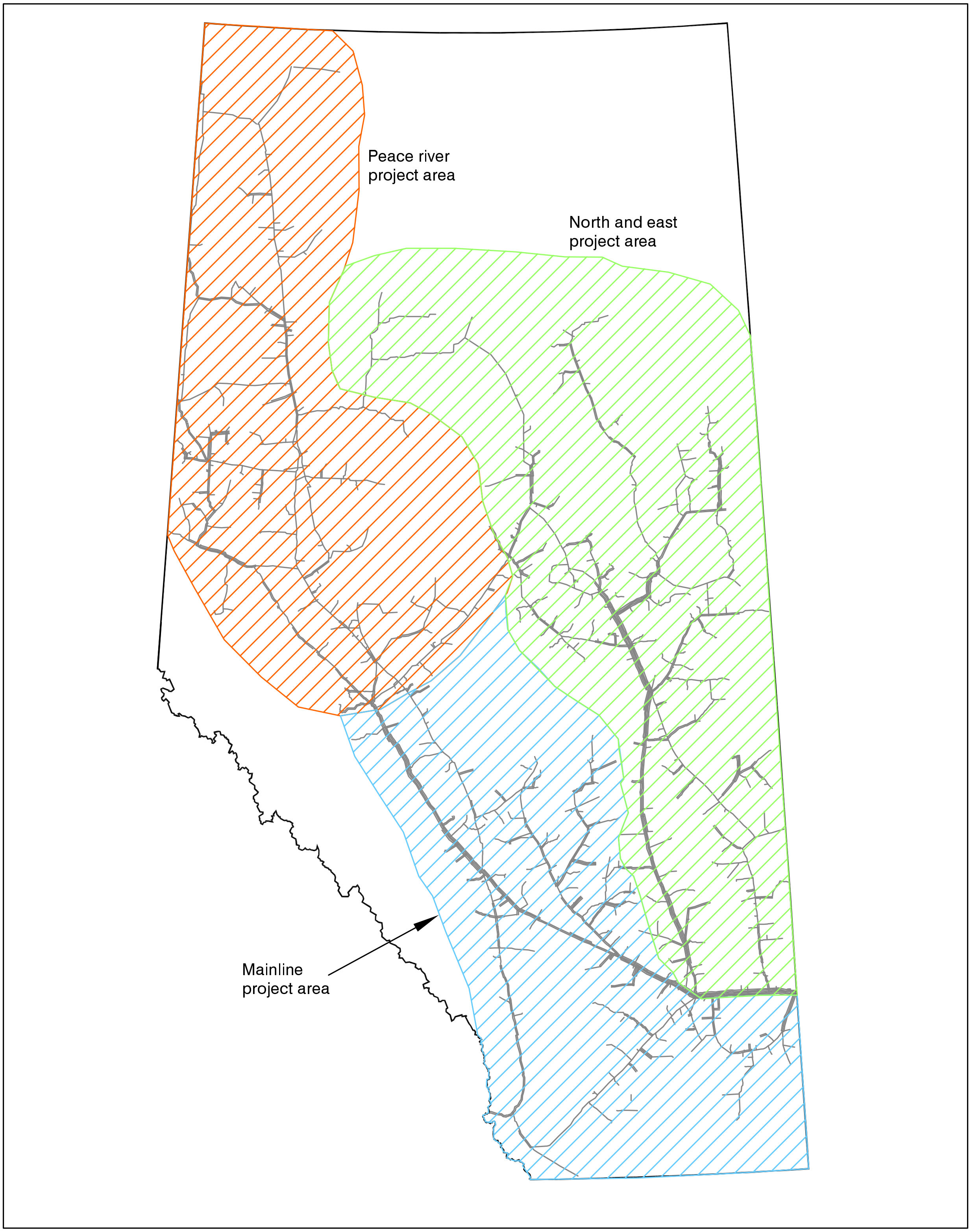

Figure 3. NOVA Gas Transmission Ltd. project areas
Application no. 990157
NOVA Gas Transmission Ltd.

Decision 2000-6

Views of Others

Alberta Treaty Eight, ProGas and SEPAC submitted that they did not support NGTL's proposed terms and conditions of service, as they believed that they would reduce a shipper's flexibility. ProGas added that the existing terms and conditions of service, established in *Decision U96055*, already recognized the need to increase accountability while maintaining flexibility. In ProGas's view, no evidence was submitted to suggest that the already approved terms and conditions were ineffective in establishing the desired balance.

ProGas submitted that NGTL's current policy with respect to transfers and term swaps should be maintained. It did not believe that either of NGTL's proposed changes was necessary given the existing restrictions on term swaps and transfers or the manner in which NGTL designed its system. It was ProGas's understanding that NGTL's mainline facilities were designed on an overall system basis to reflect the aggregate of all receipt contracts. Therefore, in ProGas's view, these additional restrictions would not increase mainline accountability. Instead, it believed that NGTL's proposal would simply reduce the flexibility currently afforded a shipper to optimize its firm receipt transportation by moving it to where it has supply. According to ProGas, this would reduce the value of firm transportation and therefore may discourage firm contracting on the NGTL system, thereby decreasing its overall efficiency.

Views of the Board

The Board understands the concerns regarding the proposed terms and conditions for receipt transfers and term swaps, since the new terms may be viewed as more restrictive. However, the Board also believes that in order to increase cost accountability, it is necessary to reflect the true cost of operational flexibility as accurately as possible. The Board considers that NGTL's proposed terms and conditions applicable per Project Area will help to achieve the desired level of accountability and will discourage uneconomic expansion of the NGTL system, an endeavour desirable by all parties. Moreover, the proposed conditions on receipt transfers and swaps are consistent with the receipt point tolling, as these would discourage shippers from hopping to receipt points with lower receipt tolls without accounting for the impact on downstream facilities. Therefore, the Board agrees that requiring an additional three-year Secondary Term when a customer transfers or term swaps service to another Project Area would increase accountability for the associated downstream mainline facilities in the area where service is requested.

The Board concludes that given the approved tolling methodology and the importance of discouraging uneconomic system expansions, NGTL's proposal for receipt transfers and term swaps is reasonable. The Board also reaffirms the current practice of not allowing receipt transfers or swaps within the Primary Term.

7 OTHER MATTERS

7.1 Administrative Fee

Views of NGTL

NGTL proposed an annual administration fee of $48 000 to each Transportation Account that it maintained. It explained that customers would be invoiced one-twelfth of the administration fee ($4000) as a minimum charge at the end of each month. NGTL submitted that this minimum monthly charge would only be offset by cumulative transportation charges at the end of the calendar year.

NGTL stated that the objective of the administration fee was to introduce direct accountability for costs, such as providing information through the energy highway, performing NIT transactions, balancing accounts on a daily basis, and providing operational information as required. NGTL believed that the administration fee would introduce an appropriate level of accountability for those costs by requiring a minimum direct contribution to the costs that are driven by each account.

Views of Others

Several of the intra-Alberta consumers submitted that they opposed the administration fee that NGTL was advancing. CANFOR, CCA, GasAlberta, IGCAA, and PICA believed that NGTL's administration fee would discriminate against intra-Alberta consumers that do not have the ability to offset the fee against actual receipt or delivery contracts with NGTL. CANFOR added that the administration fee would constitute a barrier to access for small- to medium-sized customers who directly or indirectly access the NIT pool from time to time in order to manage their energy requirements. GasAlberta added that there was no evidence that the receipt toll would not continue to recover 100 per cent of these administrative fees. GasAlberta and PICA also submitted that no cost of service study had been undertaken to justify the fee.

Views of the Board

The Board notes the wide agreement among intra-Alberta shippers that the proposed administrative fees are discriminatory against domestic consumers. The tolling design, whether current or proposed, may not provide an adequate incentive for intra-Alberta customers to hold receipt contracts and thus they would be disadvantaged since such fee cannot be offset by transportation costs. In addition, the Board notes that no evidence was submitted in support of the reasonableness of the level of the fee. Rather it appears to have been determined arbitrarily during discussions with stakeholders that do not appear to have included representatives of intra-Alberta customers. The Board finds that there is no basis to determine that the proposed administrative fee is appropriate. On that basis they cannot be ruled as just and reasonable and is therefore denied.

7.2 Code of Conduct and Implementation Schedule

Views of NGTL

NGTL submitted that the approval and implementation of the application could proceed without a finalized Code of Conduct in place. It disagreed with CAPP over the interpretation of a term in the MOU dealing with the Code of Conduct. NGTL stated that approval of the application was not conditional on the resolution of the Code of Conduct matter and that, in fact, there was an existing Code of Conduct for NGTL and its affiliates. In NGTL's view, such a precondition was neither necessary nor in the public interest. NGTL added that substantial progress had been made with CAPP on revising the current codes. Moreover, any concerns about undue affiliate preference could ultimately be remedied through recourse to the Board, a remedy that was not restricted by the development of a new Code of Conduct.

NGTL argued that, like its customers, it required certainty respecting services and pricing in order to make critical decisions respecting commercial options for transportation service. To accommodate this, it requested a decision from the Board no later than January 2000 and a commencement date of April 1, 2000, or alternatively to occur on the first day of the month occurring 56 days following the Board's'decision. NGTL submitted that shippers would make their decisions regarding their transportation needs within two weeks of the Commencement Date. It stated that any delay in the determination and implementation of the application would significantly and adversely impact existing and potential customers that must make a choice early in 2000 between competing transportation alternatives. NGTL explained that absent of full implementation of the application early in 2000, existing and potential customers would be forced to make commitments on either the NGTL or Alliance systems without knowing the rate structure or service offerings that would apply to NGTL. In its view, this would clearly put it at a disadvantage, with an unknown service offering and rate design versus a known competitor's offering.

NGTL also submitted that the implementation schedule was based on the timing required to make the business process and computer system changes required to implement the application. With respect to the concerns of ProGas that the implementation period was too short, NGTL responded that it had assumed that customers would plan for the implementation prior to the EUB decision and it had made tools available to customers to assist them in their planning.

Views of Others

CAPP, Clan Duncan, Imperial, PanAlberta, and PanCanadian submitted that their support for the NGTL application was conditional upon the resolution of the Code of Conduct. Therefore, these parties requested that the Board delay the implementation of the applied-for toll design until there was a satisfactory resolution to the Code of Conduct matter. CAPP testified that implementation of the application prior to a finalized Code of Conduct would not be in the interests of natural gas producers. Clan Duncan added that it would like the proposed Code of Conduct to be approved by the interested stakeholders, itself included. Clan Duncan submitted that if a satisfactory agreement could not be reached, the application should not be implemented unless NGTLs affiliates were prohibited from competing in the area of construction of connecting facilities. CAPP also submitted that it agreed with NGTL that implementation of the application by April 1, 2000 was important. However, CAPP indicated that if there was no Code of Conduct in place by that time, it was still its position that implementation date should be delayed.

PICA agreed with these parties' recommendation to delay implementation of any new rate structure until a satisfactory Code of Conduct was reached. Calgary expressed the view that the proper procedure would have been to first resolve the Code of Conduct matter or alternatively, that NGTL should have independently proposed a Code of Conduct as part of the application.

ProGas submitted that the implementation schedule NGTL proposed would not allow enough time for shippers who currently had a portfolio of contracts under the current NGTL toll mechanism to make prudent decisions. Therefore, ProGas requested that if the application were approved the Commencement Date be a minimum of six months following the Board's decision. It explained that it currently has 2800 firm receipt service contracts with 170 producers at over 260 receipt points, totalling approximately 1.2 billion cubic feet per day. ProGas indicated that any amendments to its sales contracts would have to be balloted and approved by its producers. Therefore, it believed that in order to make the necessary amendments to its gas purchase contracts, gas sales arrangements, and decisions respecting its firm transportation service, it would require at least six months. ProGas added that it would not be prudent to start the processing of amending contracts until the Board released its decision. Therefore, in ProGas's view, the eight-week time frame between the approval of the application and the Commencement Date proposed by NGTL was unrealistic. In its view, it ignored the realities of the business of one of NGTL's largest customers and was extremely unfair and prejudicial. It also submitted that it did not see any reason why the Commencement Date could not be delayed, in fact, to November 1, 2000.

Views of the Board

The Board notes that the majority of participants called for a proper Code of Conduct to be in place prior to implementation of either the entire Agreement or at least certain elements, such as New Services and New Facility Construction. CAPP's testimony, supported by other producers who participated in the proceeding, clearly indicated that in its view a nonconditional approval of the application as filed would not be in the interest of natural gas producers. Clan Duncan, a competitor of certain of NGTL's affiliates, stressed that competition in lateral construction cannot be fair unless there is a proper Code of Conduct in place. Many of the intra-Alberta customers also called for a proper Code of Conduct. PanAlberta, representing a marketer perspective, also was in support of a Code of Conduct.

The Board understands that the interveners' concern with the Code of Conduct related mainly to the New Services and New Facility Construction proposals. The Board has already determined that the New Services proposal is not in the public interest. As to the construction of new receipt and delivery laterals, the Board has concluded that NGTL's affiliates cannot participate unless a Code of Conduct is in place. The Board believes that the onus is on NGTL to ensure that a satisfactory Code of Conduct is in place to enable its nonregulated entities to compete in the construction of new lateral facilities. Given the Board's decision on these two items of the Agreement, the Board believes that implementation of the approved elements of the application do not need to be subject to a Code of Conduct being in place.

The Board notes that CAPP, NGTL and others are currently in the process of negotiating such a Code of Conduct. It is the expectation of those parties that upon completion of these negotiations, the proposed code will be filed with the Board. In the event that NGTL believes that no further progress or resolution can be achieved, it could on its own volition file its proposed Code of Conduct with the Board.

The Board has considered ProGas's concerns that the time frame between the approval of the application and the Commencement Date proposed by NGTL was unrealistic. However, as noted earlier in this report, the Board is mindful of NGTL's preference for an expedited implementation process in order to deal with the perceived impacts of pipe-on-pipe competition. The Board does believe that it is obligated to provide its regulated utilities with the tools necessary to be commercially successful. In this case, although the Board expects that the time frame will be difficult for some customers to meet, the benefits arising from an earlier implementation date outweigh the potential costs. The Board expects that NGTL, particularly since it is responding to potential competition, will be strongly motivated to respond diligently in assisting its customers to adapt to the new tolling methodology.

Given the above, the Board directs that the Commencement Date of its approvals shall occur on the first day of the month occurring eight weeks following issuance of this decision, subject to approval of the compliance tariff filing.

7.3 Compliance Tariff Filing

Views of NGTL

NGTL submitted that it was not asking the Board to approve the tariff language filed with the application at this time. Nonetheless, it did believe that the wording that was before the Board fairly reflected the changes that were outlined in the application. NGTL indicated that over the next four to six weeks discussions would be held with its stakeholders regarding the new tariff and terms and conditions of service. Therefore, it expected to file a revised tariff for approval prior to a Board decision on the application.

Views of Others

CAPP, Imperial, and PanAlberta submitted that the Board should not approve the tariff as filed at this time. CAPP explained that the tariff language being put forward to the Board was draft and not in its final form. These parties indicated that the tariff language would be discussed through a stakeholder process and the final tariff language would be filed with the Board upon completion.

Views of the Board

The Board accepts that NGTL is actively examining the language of the tariff with its customers. A large number of proposals have been addressed in this decision that will likely require revisions to NGTL's tariffs and terms and conditions of service. Therefore the Board accordingly directs NGTL to revise its tariff to incorporate the findings of this decision. NGTL is to file these revisions with the Board and interested parties 21 days after this decision is issued.

7.4 Future Load Retention Services

Views of NGTL

In its written evidence, NGTL stated that it intended to offer a future Load Retention Service that would enable it to respond to competitive bypass pipelines in much the same way that it had already responded to the competitive threat posed by the proposed Palliser and Coleman pipelines. In doing so, NGTL indicated that it would continue to abide by the negotiated conditions of the MOU. The company indicated that it was willing to reduce the Total Revenue Requirement of its system by 25 per cent of the annual difference between the potential revenues without Load Retention Service and the actual revenues with the service. Any future Load Retention Service would be offered for the duration of the two-year Initial Period and NGTL shareholders would assume part of the revenue losses. This, it believed, would help assure others that NGTL would negotiate a reasonable service arrangement with customers that might otherwise bypass its system. Shareholder contribution beyond the Initial Period would be determined by agreement among NGTL, NGTL shareholders, CAPP, and other parties to the MOU. Load Retention Service conditions negotiated during the Initial Period would remain in effect until the EUB approved the amended tariff.

NGTL maintained that the MOU, provided for CAPP not opposing NGTL's proposed future load retention services during the Initial Period, conditional upon NGTL being subject to a prudency review. Such a review would be initiated by parties to the MOU that believed that NGTL did not act appropriately in offering or negotiating an acceptable load retention service. The TTP or its successor would conduct the review. Should an NGTL decision be deemed imprudent, impacted parties would have recourse to ask the Board to review the evidence of negative impacts and recommend suitable action.

NGTL also proposed that, should a third-party competitor intend to build 400 MMcf/d or more of incremental transportation capacity, it should be free to make a pricing adjustment. Before making any changes to the Price Floor and Ceiling or rate design, NGTL agreed to meet with CAPP and negotiate a satisfactory solution. Barring an agreement, any affected party would be entitled to ask the Board to determine and sanction an appropriate pricing methodology.

Views of the Board

The Board notes that the parties at the hearing did not dispute these provisions of the MOU. The Board also acknowledges that NGTL has valid concerns regarding its ability to respond to the threat posed by competitive bypass and understands the need for NGTL to offer future load retention services. In general, the principles proposed to ensure that NGTL is protected from economically inefficient bypass appear to be reasonable. The proposal also appears to offer adequate protection for parties that believe they may have been adversely affected to have their concerns resolved. Therefore, the Board would encourage all parties involved to consider this element of the MOU when faced with assessing the impacts of future load retention services.

7.5 Dispute Resolution, Reporting Requirements, and Audit Rights

Views of NGTL

NGTL submitted that the parties to the Agreement wished to continue to foster a long-term mutually beneficial relationship and implement an informal mechanism for the resolution of disputes under the MOU. According to NGTL, one party may at any time notify the other of an intention to discuss or dispute any matter connected with the Agreement. NGTL explained that if a satisfactory resolution could not be achieved within 30 days from the date of notification, either party may file an application with the EUB requesting the EUB to adjudicate the matter in dispute. It added that any application filed with the EUB must contain a request that the matter in dispute be dealt with on an expedited basis. NGTL also indicated that the application could contain a request for an interim order pending the EUB’s final decision with respect to the matter.

In addition, NGTL submitted that it would have reporting obligations and its customers would have full audit rights with respect to the provisions of the Agreement. NGTL also indicated that it would regularly report the list of new services and their costs. However, it would not be required to disclose the profits or revenues it received from new services. NGTL added that an industry task force would be formed to scope out the content and format of the reports for tolls, load retention services and new services.

Views of the Board

The Board is supportive of any mechanism that results in acceptable negotiations provided that they are fair and accessible to all affected parties. The Board reminds both NGTL and CAPP that to be truly successful, such discussions must be as inclusive as possible.

The Board is also encouraged by the proposed dispute resolution mechanism as proposed, but would expect NGTL to work towards ensuring the involvement of all stakeholders. The concepts of reporting obligations and the provision to customers of full audit rights with respect to certain provisions of the Agreement, such as tolls and load retention services are attractive. An industry task force to scope out the content and format of the tolls, as proposed in the MOU, would enhance public understanding and acceptability of the new rate design.

7.6 Terms of Certain Elements of the MOU

Views of NGTL

NGTL submitted that many concepts within the MOU and hence the application were foundational in nature and were intended to continue in effect until such time as any subsequent amendment to the tariff was approved by the EUB. NGTL indicated that these concepts included:

- receipt point specific rates methodology
- renamed services
- contract renewal provisions

- receipt transfers and term swaps
- new facility construction and pricing provisions
- load retention services negotiated during the Initial Period
- revenue collar
- administration fee
- reporting and audit requirements
- contract term differentiation (excluding the specific term differentials).

In addition, NGTL explained that many provisions in the Agreement were to be applicable only for the Initial Period, which was intended to be a learning period in which market information would be collected and specific numbers would be tested. NGTL submitted that the following aspects of the Agreement would only be applicable during the Initial Period:

- Load retention service provisions
- New services
- Specific premiums and discounts associated with term-differentiated tolls
- IT-R, IT-D, and STFT premium revenue sharing
- Revenue collar set at $5 million
- NGTL's $50 million contribution to the transition

NGTL indicated that 12 months prior to the expiration of the Initial Period it would hold discussions with CAPP to review the aspects of the Agreement that were only applicable during the Initial Period. NGTL explained that during these discussions the parties would review and agree on the aspects that need to be replaced, amended, or terminated. NGTL submitted that if the parties were unable to reach an agreement on certain aspects of the application, then those aspects would be terminated at the end of the Initial Period. NGTL added that its intention was to file an application prior to the end of the Initial Period to address those elements of the rate design that would only be implemented for the Initial Period.

NGTL submitted that the parties to the MOU agreed that the provision respecting the Price Floor and Ceiling for receipt point pricing would be in effect for the balance of the calendar year in which the Commencement Date occurs and for the next three calendar years thereafter. NGTL indicated that it would make an application to the EUB at an appropriate time with respect to receipt point pricing to take effect following the Transition Period. NGTL added that the Price Floor and Ceiling could only be changed in the interim if it was replaced, amended, or terminated by the EUB.

Views of the Board

The Board is prepared to endorse the concept of a test period, as it appears to provide a reasonable opportunity for change while attempting to reduce risk to a manageable level. As the Board noted earlier, the incorporation of a transitional period, when there is a significant deviation from a current process, is also a positive attribute.

7.7 Contribution to the Transition Period

Views of NGTL

NGTL submitted that the provisions of the Agreement called for it, as well as customers, to contribute towards the revenue shortfall that would occur during the Transition Period as a result of the implementation of the Price Floor and Ceiling. NGTL and customer contributions were set at $25 million and $20 million respectively for each of the first two years of the Transition Period. NGTL explained that these contributions would have the effect of cushioning the impact on customers of the revenue shortfall caused by rates rising to the Price Ceiling slower than rates falling to the Price Floor over the Transition Period.

Views of the Board

The Board notes the proposal for contribution towards revenue shortfall but is also mindful that many elements of the original Agreement will be affected by the decisions rendered in this report. Therefore, the Board expects that the ongoing applicability of this, plus several other issues, will need to be considered further by all of the parties.

8 ORDER

Therefore, it is ordered that NGTL shall incorporate the findings of this decision in its tariff and terms and conditions of service and shall file these revised tariffs and terms and conditions of service with the Board 21 days after issuance of this decision.

Dated in Calgary, Alberta, on February 4, 2000.

ALBERTA ENERGY AND UTILITIES BOARD

B. F. Bietz, Ph.D.
Chair

J. D. Dilay, P.Eng.
Member

F. Rahnama, Ph.D.
Acting Member

APPENDIX 1 – THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
NOVA Gas Transmission Ltd. (NGTL) H. D. Williamson, Q.C. P. M. Keys	E. Shelton, P.Eng. D. J. Cornies, P.Eng. D. K. Ferguson N. Bowman K. B. Johnston, of H. Zinder & Associates
AEC Marketing R. Fraser	
Alberta Department of Resource Development R. Estabrooks	
Alberta Irrigation Projects Association J. H. Unryn	
Alberta Treaty Eight Bands and Natural Resource Initiative (Alberta Treaty Eight) J. Graves R. C. Secord	
AltaGas Services Inc. G. Malin	
Amoco Canada Petroleum Company C. Worthy	
Anderson Exploration Ltd. L. Horn	
ATCO Gas (ATCO) L. E. Smith N. M. Gretener E. R. Bourgeault	J. F. Engler J. P. Lukens, Ph.D., of Lukens Consulting Group Inc. G. M. Engbloom, P.Eng., of Confer Consulting Ltd.

Principals and Representatives	Witnesses
Canadian Association of Petroleum Producers (CAPP) N. J. Schultz	G. L. Stringham, P.Eng. R. M. Cusson, of Canadian Natural Resources Limited R. B. Pardy, P.Eng., of Tethys Energy Inc. G. MacGillivray, of Suncor A. Safir, Ph.D., of Recon Research Corporation
Canadian Forest Products Limited (CANFOR) L. L. Manning	
City of Calgary (Calgary) R. B. Brander	
Clan Duncan Resources Ltd. (Clan Duncan) G. Fitch R. Hillary	
Consumers Coalition of Alberta (CCA) J. A. Wachowich	
CrossAlta Gas Storage and Services Ltd. P. Glashier	
Ermineskin Band B. Small	
Enron Capital and Trade Resources Canada Corporation R. Hemstock	
Foothills Pipe Lines Ltd. P. Cochrane	
GasAlberta Inc. (GasAlberta) T. D. Marriott	
Imperial Oil Resources Limited (Imperial) R. Moore	

Principals and Representatives	Witnesses
Industrial Gas Consumers Association of Alberta (IGCAA) A. L. McLarty B. J. Roth	N. E. MacMurchy M. R. Thomas, P.Eng., of NOVA Chemicals Corporation P. J. Milne, of Peter J. Milne &Associates Inc. W. Y. Svrcek, P.Eng., Ph.D., of the Department of Chemical & Petroleum Engineering, University of Calgary
Mobil Oil Canada B. Woods	
Pan-Alberta Gas Ltd. (PanAlberta) E. S. Decter	
PanCanadian Petroleum Limited (PanCanadian) D. G. Davies	N.M. Laird R.K. Powell, P.Eng. M. Drazen, of Drazen Consulting Group
Phillips Petroleum Resources Ltd. (Phillips) A. G. MacWilliam	J. Taylor
Poco Petroleums Ltd. S. Brasso	
ProGas Limited (ProGas) A. S. Hollingworth M. L. Voinorosky Janice R. M. Kowch	K. J. MacDonald R. D. Skinner T. S. Yanota, P.Eng.
Public Institutional Consumers of Alberta (PICA) R. T. Liddle, P.Eng. N. J. McKenzie	
San Diego Gas and Electric Company T. M. Hughes	

Principals and Representatives	Witnesses
Shell Canada Limited J. P. Jamieson	
Small Explorers and Producers Association of Canada (SEPAC) H. R. Ward	R.E. Vogel, of Beau Canada Exploration Ltd. P. M. Nettleton, P.Eng., of Peter M. Nettleton Consulting Ltd.
Suncor Energy Inc. (Suncor) G. MacGillivray	
Talisman Energy Inc. F. Basham	
TransCanada Gas Services M. Samuel	
TransGas Limited M. Wappel	
Western Export Group (WEG)[5]	J. P. Armato C.K.Yates, of Pacific Gas & Electric Company K. C. Olsen of BC Gas Utility Ltd. R. T. Ballantyne, P.Eng., of BC Gas Utility Ltd. W. F. Donahue, of Puget Sound Energy, Inc.
Alberta Energy and Utilities Board Staff G. A. Habib D. A. Larder, Counsel M. M. Kruzel E. A. Smith	

[5] WEG comprises Pacific Gas & Electric Company, BC Gas Utility Ltd. and the Alberta Export Group which includes Avista Corporation, Duke Energy Trading and Marketing , L.L.C., IGI Resources, Inc., Intermountain Gas Company, Northwest Natural Gas Company and Puget Sound Energy, Inc.

APPENDIX 2 – GLOSSARY OF TERMS AND ABBREVIATIONS

Accord, the	"Agreement on Natural Gas Pipeline Regulation, Competition and Change to Promote a Competitive Environment and Greater Customer Choice," dated April 7, 1998, and signed by CAPP, NOVA Corporation, NGTL, SEPAC, and TCPL
AFRSP	Average Firm Receipt Service Price
Agreement, the	See MOU
application, the	NGTL Products and Pricing Application No. 990157
CEIS	Cost Efficiency Incentive Settlement approved by EUB Order U96119
Commencement Date	The first day of the month occurring 56 days following Board approval
FLC	Facility Liaison Committee
FT-D	Firm Transportation Delivery
FT-R	Firm Transportation Receipt
GRA	Phase II of NGTL's 1995 General Rate Application
Guidelines, the	Alberta Energy and Utilities Board's Negotiated Settlement Guidelines
Initial Period	24 months following the Commencement Date
IT	Interruptible Service
IT-R	Interruptible Receipt
IT-D	Interruptible Delivery
LDS	Local Delivery Service
LRS	Load Retention Service, as approved per Board's Decision U97096
LRS-2	Load Retention Service, as approved per EUB Order U99042
Mcf	Thousand cubic feet

MMcf	Million cubic feet
MOU	Memorandum of Understanding signed between NGTL and CAPP on March 16, 1999
NIT	NOVA Inventory Transfer
Pilot Services	Current Pilot Services being tested are Storage Interruptible Prioritization Pilot, Alternate Access of Firm Service (Export Delivery), and the Pilot Procedures for Supply to Demand Balancing (effective April 1, 1996)
Primary Term	The number of years of service under a schedule of service under rate schedule FT-R required for the cumulative present value to equal or exceed the cumulative present value cost of service
Secondary Term	Three-year extension in the contract term for new receipt service over and above the Primary Term
STFT	Short-Term Firm Transportation
Transition Period	A four-year period over which price floors and ceilings are in effect
TTP	Tolls, Tariffs, and Procedures Committee
WCSB	Western Canadian Sedimentary Basin

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

ALTAGAS UTILITIES INC.	Decision 2003-052
INTERIM RATES FOR THE	Application No. 1302431
BONNYVILLE SERVICE AREA	File No. 1402-11

1 INTRODUCTION

By letter dated May 22, 2003, AltaGas Utilities Inc. (AltaGas or the Company) filed an application with the Alberta Energy and Utilities Board (EUB or the Board), requesting approval of interim refundable rates and terms and conditions of service for the Bonnyville service area (the Application).

The Board provided Notice of the Application, dated June 3, 2003, to all interested parties and published it in local newspapers on or about June 10, 2003. Any party wishing to provide a submission was to do so by June 18, 2003. The Board indicated that in the absence of any opposition to the Application it would proceed to process the Application.

2 DETAILS OF THE APPLICATION

AltaGas submitted that customers in the Company's Bonnyville service area (previously served by Bonnyville Gas Company Limited) paid for their natural gas distribution service through rates approved in Decision U98059, dated May 20, 1998, based on the 1999 test year. At that time, Bonnyville Gas Company Limited (Bonnyville Gas) operated as a distinct and separate natural gas distribution utility, but subsequently amalgamated with AltaGas in 2001. The merger of the two companies was recognized in the second and third test years of the three-year 2000/2001/2002 AltaGas General Rate Application (GRA). In Decision 2002-067, dated August 6, 2002, the Board approved the revenue requirements for 2000, 2001, and 2002. The Decision set the revenue requirements on a non-consolidated basis for 2000 and on a consolidated basis for 2001 and 2002.

In the Application, the Company sought to align its rates with its regulatory structure and specifically requested approval of interim refundable rates for the Bonnyville service area. The interim rates would then be the same as the natural gas distribution and transportation postage stamp rates currently charged to customers in the rest of the AltaGas service area. (Customers of the Bonnyville service area had been charged the same Gas Cost Recovery Rate as the rest of AltaGas customers since the summer of 2001.)

The Company indicated that only Rate 1 and Rate 2 customers would be affected by the change. Rate 3 customers would be unaffected by the change because the Bonnyville service area rate for Rate 3 customers was the same as the rate for all other AltaGas Rate 3 customers. No other rates were affected.

Specifically, AltaGas indicated that the Rate 1 base energy charge would increase by $0.047 per gigajoule (GJ) to $1.293/GJ and Rate 2 base energy charge would increase by $0.027/GJ to $0.725/GJ, with fixed charges for both rate classes remaining unchanged.

The Company proposed that Bonnyville service area customers adopt AltaGas' terms and conditions of service, indicating that the terms and conditions of service last approved for Bonnyville Gas currently applied to the customers of the Bonnyville service area. The Company indicated that terms and conditions of service approved for Bonnyville Gas were essentially the same as those in effect for AltaGas.

The Company proposed to incorporate Bonnyville's Rate Rider "A" into AltaGas' Rate Rider "A" schedule.

The Company proposed that the refundable interim rates, changes to terms and conditions of service, and merger of rate rider schedules be made effective July 1, 2003. The Company stated that a revenue excess/deficiency specific to different rate classes would accumulate from January 1, 2003 until such time that the rates were aligned. The Company proposed that any reconciliation would be dealt with in the Company's next GRA, which AltaGas expected to submit during the second quarter of 2003.

3 VIEWS OF THE PARTIES

In response to the Board's Notice, a submission was received from the Consumers' Coalition of Alberta (CCA), dated June 19, 2003.

Views of the CCA

The CCA noted that the existing rates for customers were based on rates determined for Bonnyville Gas from its 1999 test year. The CCA observed that under the Company's proposal, the Bonnyville customers taking service under Rate 1 would see an increase of $0.047/GJ ($1.246/GJ to $1.293/GJ) in base energy charges effective July 1, 2003. Rate 2 customers would see a corresponding increase of $0.027/GJ ($0.698/GJ to $0.725/GJ) to get into alignment with the existing AltaGas rates. The CCA submitted that using the differential with existing rates, customers in Bonnyville service area would have accrued a total revenue deficiency of $122,282 from 2000 to June 30, 2003.

The CCA argued that if the rates proposed by AltaGas in its current Phase II portion of its GRA were approved, the accumulated deficiency since 2000 to June 30, 2003, attributable to the Bonnyville service area customers, would be only $17,222. The CCA further argued, that while there would be a slight increase to the Bonnyville service area Rate 1 customers' base energy charges of $0.017/GJ ($1.246/GJ to $1.263/GJ), or 1.36%, under AltaGas' proposed rates, the base energy charges for all other customers were expected to decrease when compared to the existing Bonnyville service area rates.

It appeared to the CCA, that overall, the customers formerly in the Bonnyville Gas franchise area would experience an increase in base energy rates if the Application was approved, only to see a reduction in rates if and when AltaGas' proposed Phase II rates were approved as filed.

Based on the foregoing, the CCA did not agree with AltaGas' proposed alignment of the rates. The CCA did agree that there was a deficiency accumulating when the existing Bonnyville service area rates are compared to the AltaGas rates as proposed in the Phase II application. The CCA argued, however, that the combined deficiency of $17,222 was not material enough to warrant collection through a rate rider at this time.

Views of the Applicant

AltaGas provided rebuttal to the CCA's position by letter dated June 23, 2003. AltaGas was concerned that the CCA had misunderstood the purpose of the Company's request.

AltaGas stated that since the 2001 test year, AltaGas Utilities Inc. had existed as a fully consolidated company, from a corporate and regulatory perspective and that in Decision 2002-067, dated August 6, 2002, the Board approved a consolidated rate base and revenue requirement for the 2001 and 2002 test years. AltaGas noted that what had been two separate distribution utilities (Bonnyville Gas Company Ltd. and AltaGas Utilities Inc.) prior to 2001 had become a single regulated entity in 2001 (AltaGas Utilities Inc.).

AltaGas argued that the main purpose of the proposal was to harmonize the Bonnyville service area rates with the rest of the Company. AltaGas noted that, for two full test years, it had been regulated as a single entity and, as a matter of principle, believed it was important that the rates charged to its customers reflected the regulatory structure. The Company noted that it had yet to file its 2003/2004 GRA, but indicated that the Bonnyville service area would continue to be consolidated with the rest of the Company.

AltaGas took issue with the CCA's reference to an "accrued" deficiency, dating back to the 2000 test period, and in particular with the CCA position that:

> …customers in Bonnyville area will have accrued a total revenue deficiency of $122,282 from 2000 to June 30, 2003.

The Company contended that 2000, 2001, and 2002 revenue deficiency matters had been addressed in prior proceedings, and stated that due to timing, rates proposed for the 2000/2001/2002 GRA could not be put in place prior to the end of the test period. AltaGas indicated that this had necessitated a rider to distribute excesses that accumulated over the 2000, 2001, and 2002 test years. AltaGas noted that on March 25, 2003, the Board had issued Decision 2003-024, approving the Company's proposal to distribute revenue excesses and other gains resulting from the 2000/2001/2002 GRA Phase I process. AltaGas argued that the GRA Phase I Decision also took into consideration the amalgamation of Bonnyville Gas Company Ltd. and AltaGas Utilities Inc. in the 2001 and 2002 test years.

AltaGas submitted that, in its original filing of May 22, 2003, it had stated:

> A revenue excess/deficiency specific to different rates would accumulate beginning January 1, 2003 until such time that the rates are aligned.

The Company argued that aligning rates within the Company as soon as possible would minimize the difference caused by non-consolidated rates. AltaGas believed that this was a matter that would need to be addressed in the 2003/2004 GRA, which the Company expected to file near the end of the second quarter.

AltaGas argued that aligning the Bonnyville service area rates with the rest of the Company should help make AltaGas' rate structure more understandable to its customers. AltaGas argued that since Bonnyville Gas Company Limited had been amalgamated with the Company for over two years, the customers would more easily understand a consolidated set of rates.

4 VIEWS OF THE BOARD

The Board has reviewed the position of the parties and notes the desire of the Company to align the rates throughout its service area into a single rate for each class of customer. In particular, the re-alignment would affect only Rate 1 and Rate 2, since other rates are already the same. The Board also notes the CCA's concern that the re-alignment is accomplished by increasing both Rate 1 and Rate 2 in the Bonnyville service area, which could then be followed by a rate decrease when the 2000/2001/2002 GRA Phase II is completed. The decrease would occur if and when AltaGas' proposed postage stamp rates are approved following completion of the Phase II.

Notwithstanding the magnitude of the excess/deficiency that might accumulate from January 1, 2003, the Board agrees with the CCA that an increase in rates followed quickly by a decrease is of concern. The Board considers that volatility of this nature in rates within a short time frame is undesirable.

Also of concern to the Board is the fact that Phase II of the 2000/2001/2002 GRA, which includes a proposal for postage stamp rates, has not yet been completed. The Board recognizes that this proposal is likely to be an issue in Phase II, and that pending completion and evaluation of that proceeding, interim approval of the Company's request for alignment of rates might be premature.

The Board notes that, while consolidation of Bonnyville Gas and AltaGas and approval of a single revenue requirement for 2002 sets the base on which new rates can be established, this does not imply that postage stamp rates will necessarily be approved in the Phase II process. The Board notes that, historically, operating with a single revenue requirement and multiple rate zones has been an accepted standard for Alberta utilities, and that the establishment of more than one rate for similar classes of customers is normally accomplished through the cost of service study presented during a Phase II process. As indicated above, since this issue of the rate setting process has yet to be fully tested and evaluated for AltaGas, the Board is concerned that approval of this Application could potentially preempt the appropriate review of the implementation of postage stamp rates and send an inappropriate signal to parties involved in the process.

Therefore, for all of the above reasons, the Board hereby denies the Application.

Dated in Calgary, Alberta on July 2, 2003.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

R. G. Lock, P. Eng
Presiding Member

(original signed by)

Gordon J. Millar
Member

(original signed by)

J. Gilmour
Acting Member

Decision 2003-090

AltaGas Utilities Inc.

Interim Refundable Rates & Harmonization of Bonnyville Service Area's Rates

November 25, 2003

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2003-090: AltaGas Utilities Inc. Interim Refundable Rates
and Harmonization of Bonnyville Service Area's Rates
Application No. 1315409

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Application No. 1315409
File No. 1402-13

1 INTRODUCTION

The Alberta Energy and Utilities Board (EUB or the Board) received an application (the Application) from AltaGas Utilities Inc. (AUI, AltaGas or the Company) by letter dated September 29, 2003, requesting approval of interim refundable rates with respect to the 2003/2004 General Rate Application (No. 1305995). AltaGas requested permission from the Board to implement interim refundable rates that provide relief to customers served under Rates 2/12 and 3/13; and approval of a harmonization of Bonnyville Service Area's rates.

The Board provided Notice of the Application to all interested parties and published it in local newspapers on October 15, 2003. Any party wishing to provide a submission was to do so by October 21, 2003.

The Board received the following submissions from intervenors that expressed either support for or no opposition to the Application.

- On October 1, 2003, a letter from the Municipal and Gas Co-op Intervenors and the Bonnyville Municipal Intervenors expressed support for the interim rates and the need for harmonizing the Company's rate schedules.

- In an October 2, 2003 letter, the Energy Users Association of Alberta (EUAA) indicated that it did not oppose this Application on the understanding that the proposed rates are interim and refundable, while also suggesting a need for work on 2004 COSS to begin shortly.

- By letter dated October 7, 2003, the Alberta Urban Municipalities Association (AUMA) advised AltaGas Utilities that, "[Mr. Bryan] and Mr. Robert Bruggeman, as consultants, have recommended to the AUMA … support for the proposed interim rate adjustments for 2003/2004." On November 21, 2003, AUMA filed a letter with the Board in support of the proposed interim rate adjustments for 2003/2004.

- On October 8, 2003, AUI received comments from Mr. Jim Graves, representing the Alexander First Nation. Mr. Graves noted in his letter that if the Company would be willing to work with Alexander First Nation, that a mutual understanding and agreement was possible. Subsequently, on October 14, 2003, AltaGas Utilities met with Mr. Graves and legal counsel and by telephone conversation, the Company was able to address their concerns, which required clarifying that the Company's proposal was on an interim and refundable basis. To this, the Company believes that the Alexander First Nation's issues have been addressed based on the fact that the Alexander First Nation ratified the 2000-

2002 GRA Memorandum, which was also addressed in their correspondence of October 8, 2003.

- On October 21, 2003, AltaGas Utilities received a letter from the Public Institutional Consumers of Alberta (PICA) indicating that "PICA supports AltaGas's request for interim rates, including the proposed rate relief to Rates 2/12 and 3/13 and the harmonization of rates for the Bonnyville District service area."

The Board received submissions from the Consumers' Coalition of Alberta (CCA) dated October 2, 2003 and October 21, 2003, outlining its opposition to AUI's interim refundable rates application. In response to CCA's submissions, AUI filed submissions on October 6, 2003 and October 21, 2003.

The Board considers the record with respect to this application closed on November 21, 2003, the date on which the Board received confirmation of AUMA's letter in support of the proposed interim rate adjustments.

2 BACKGROUND

AltaGas filed an application on May 22, 2003, requesting approval of interim refundable rates, and terms and conditions of service for the Bonnyville service area. The new rates would affect Rate 1 and Rate 2 customers and would be identical to those being used in the balance of the AltaGas service area. The Board, in Decision 2003-052, dated July 2, 2003, denied the application. The Board agreed with the submission of the Consumers' Coalition of Alberta that rate increases, then decreases, could result from the application. The Board also determined that since the prior period Phase II was still being negotiated it would be premature to approve postage stamp rates.

The Board received a letter dated September 29, 2003 letter from AltaGas, requesting approval of the Memorandum of Agreement (MOA) and Negotiated Settlement Brief (the Agreement) reached with customers for the Phase II portion of the 2000-2002 General Rate Application (Phase II) for AUI and Bonnyville Gas Company Limited.

3 DETAILS OF THE APPLICATION

On September 29, 2003, AltaGas filed a letter with the Board requesting approval of the MOA and Negotiated Settlement Brief reached with customers for the Phase II portion of the 2000/2001/2002 General Rate Application for AUI and Bonnyville Gas Company Limited. While in support of the MOA, AltaGas noted that some customers served under Rates 2/12 and 3/13, expressed concern with the continuation of existing Rates 2/12 and 3/13 through 2003 and 2004. AltaGas submitted that the Public Institutional Consumers of Alberta asked that some relief be provided to the customers served under Rates 2/12 and 3/13. The Company requested the following changes to Rates 2/12 and 3/13:

Rate	Fixed Charge	Base Energy Charge	Demand Charge
2/12	No change.	A reduction from $0.725 per gigajoule (GJ) to $0.675 per GJ, a reduction of $0.050 per GJ.	Not applicable.
3/13	A reduction from $525 per month to $357, a difference of $150 per month.	A reduction from $0.046 per GJ to $0.028 per GJ, a reduction of $0.018 per GJ.	No change.

On an annualized basis, this represents a reduction in Rate 2/12 revenues of $58,000 and a reduction in Rate 3/13 revenues of $151,800 based on 2004 forecast billing determinants.

To offset the reduction in Rate 2/12 and Rate 3/13, AltaGas requested that interim refundable rates include an increase to the base energy charge of Rate 1/11. The Company indicated that the requested adjustment to Rate 1/11, based on 2004's forecast billing determinants, is an additional 1.5 cents per GJ to the base energy charge. This adjustment to Rate 1/11 offsets the decrease in revenue to Rates 2/12 and 2/13, basically keeping the Company's revenue deficiency forecast in 2003/2004 constant. AUI provided additional detail in terms of impact to forecast revenues by class in Appendix A(Proposed Interim Rate Adjustment & 2004 Revenue Reconciliation) of this decision.

The Company proposed that these interim rates come into effect November 1, 2003.

The Company also proposed the harmonization of rates for the Bonnyville District service area. Currently, the Company's customers served in this service area are charged rates approved by Board Decision U98059. On May 22, 2003, AltaGas applied to the Board for approval to have the same set of rates applied throughout the Company's service areas. However, by Decision 2003-052, dated July 2, 2003, the Board denied AltaGas' request. The Company submitted that different circumstances exist today, as outlined below, which require the Board to take the change in circumstances into consideration:

a. The harmonization of rates would provide relief to Rate 2/12 customers in the Bonnyville service area. The existing Rate 2/12 base energy charge is $0.698 per GJ. Harmonization of rates would reduce the rate to $0.675 per GJ, a reduction of 2.3 cents per GJ.

b. The harmonization of rates would provide the same level of relief to Rate 3/13 customers in the Bonnyville service area as those in other service areas. The existing Rate 3/13 is the same in the Bonnyville service area and thus harmonizing the rates will provide the same level of relief as specified above, under Section 1 of this Application.

c. At the time of the previous filing for rate harmonization in May 2003, there existed the possibility of a significant rate reduction to Rate 1 customers by way of the 2000/2001/2002 Phase II GRA. However, the Company and Customers recently filed a 2000/2001/2002 – Phase II GRA – Memorandum of Agreement with the Board. The MOA requested that the Board allow the rates that were in place during the 2000/2001/2002 test period, in combination with the refund of revenue excesses and gains as determined in the Phase 1 Decision 2002-067, to be considered final on the basis that the rates with the refund were just and reasonable. Although the 2003/2004 revenue requirements have yet to be tested, the Company forecasted revenue deficiencies in both test years. Therefore, the likelihood of significant short-term rate fluctuation resulting from a sudden drop and then increase to Rate 1 customers has diminished substantially.

d. The Phase II portion of the 2003/2004 General Rate Application will not contemplate different rates for the Bonnyville service area. The Company has prepared the Phase 1 portion of the 2003/2004 GRA as a consolidated filing, without any distinction between the Bonnyville service area and the rest of the Company. The Company indicated that it intended to prepare the cost of service study supporting the Phase II portion of the 2003/2004 GRA as a consolidated study. Since the consolidation of the utilities in the 2001 test year, there has been no request from our Customers to treat them separately.

AltaGas stated that the Company and its Customers have discussed this Application and given it significant consideration, with most parties indicating initial support for this proposal.

4 VIEWS OF THE PARTIES

4.1 Views of the Applicant

AltaGas Utilities submitted that it filed the Application to honor a commitment made to the group when settling the issues between the various rate classes in Phase 2 of the 2000/2001/2002 GRA. When those discussions took place, the year 2002 had ended and a 2003/2004 GRA was before the Board. AUI suggested that it was argued and accepted that the untested evidence appeared to suggest that Rates 2 and 3 might be paying more than their fair share of the costs.

Consequently, the majority of the group[1], including those other than the CCA that represent Rate 1 customers, concluded that the most sensible solution would be to try to provide limited temporary relief to Rates 2 and 3 on an interim refundable basis. AltaGas noted that there is support from those representing elected local governments, customers in all Rates 1, 2, 3 and 4, and, in fact, the vast majority of AltaGas Utilities' customers.

AUI submitted that the vast majority of AltaGas Utilities' customers have either expressed support, or at least, no objection to our proposal for interim refundable rates.

Only one customer interest group, the Consumers Coalition of Alberta (CCA), has expressed opposition to the proposal for interim refundable adjustments to existing rates although they do not object to the harmonization of the Bonnyville service area rates.

[1] The Customer Groups involved in Phase II of the 2000/2001/2002 GRA negotiations are: the Municipal and Gas Co-op Intervenors & Bonnyville Municipal Intervenors, the Alberta Urban Municipalities Association, the Public Institutional Consumers of Alberta, the Consumers Coalition of Alberta, the Energy Users Association of Alberta, and Alexander First Nation.

In its October 6, 2003 submission, AltaGas Utilities objected to the comments of the CCA that *"If the Company wishes to wrap up the 2002 Phase 2, and address the concerns of the Rate 2/12 and 3/13 customers, it should provide interim funding on its own, without asking other customers for such financing."* AltaGas argued that this was a complete misrepresentation of the process and the result. The Company submitted that the application reflects the consensus of the group on how best to deal with potential rate issues between customer classes. AUI argued that the CCA submission, in fact, conflicts with the consensus of those representing the vast majority of the customers on the system. The Company submitted that it had an obligation to the group, based on the consensus view, to bring this application forward on behalf of the group. AUI argued that if it were being brought for the Company's benefit there are many large, and essentially uncontestable, revenue deficiency items for which the Company would seek relief on an interim refundable basis.

4.2 Views of the Consumers Coalition of Alberta

In its October 2, 2003 submission, CCA argued that the Application is not typical in that AUI does not seek recovery of any portion of its forecast revenue deficiency as filed in its 2003/04 GRA. Instead, CCA noted that AUI sought to realign rates and revenues collected between customer classes, the result of which is that there is no additional revenue flowing to the Company. CCA argued that the impact of AUI's proposed rate realignment is to increase rates for Rate 1/11 by a total of $209,800. The benefit of this increase is to provide rate relief to Rate 2/12 of $58,000 and Rate 3/13 of $151,800.

In the 2002 COSS, CCA noted that AUI had filed for a revenue/cost ratio (RC ratio) for Rates 2/12 and Rates 3/13 of 114.89% and 115.64%, respectively. CCA suggested that had there been a rate hearing, the Company would have fully supported its Phase II rate application, and the resulting RC ratios as being reasonable. However, as shown in Appendix B (CCA Interim Refundable Rates Assessment), CCA submitted that the impact of the rate realignment is that it reduces the RC ratio for Rate 3/13 from 115.64% proposed in the 2002 COSS and 124.92% under existing rates to 106.2%. On the other hand, for Rates 2/12, it increases the RC ratio from 114.89% proposed in the 2002 COSS to 120.4%.

While AUI attempts to "directionally[2] address PICA's concern, CCA argued that the effect of the proposal is to worsen the RC ratio of the Rate 2/12. Effectively, CCA submitted that while Rate 2/12 would receive a small break from existing rates (from 126% to 120%), the RC ratio relative to what the Company would have filed as being appropriate in the 2002 COSS increases from 115% to 120%.[3]

CCA also submitted that the mere fact that the RC ratios are in excess of what may be considered "directionally" appropriate does not render the rates unjust or unreasonable. In several Phase II decisions, the Board has accepted the fact that rates are just and reasonable notwithstanding the fact that the RC ratios are outside the plus or minus 5% tolerance limit from unity. CCA argued

[2] The CCA submission filed October 6, 2003, p. 2 states: "While the Company does not address what it means to states that the rate realignment directionally addresses PICA's concerns, CCA assumed it to mean that it results in a RC ratio within plus or minus 5% of unity."

[3] The CCA submission filed October 6, 2003, p. 2 states "These calculations are all done using 2002 COSS data. Admittedly, using 2004 data will result in slightly different results. However, considering that Rate 1/12 make up in excess of 92% of total revenues, and will contribute to 92% of total incremental revenues in 2004, CCA concluded that the relative ratios in 2004 should not change much."

that the proper forum to revisit the RC ratios is in the context of a Phase II Filing. The only evidence CCA notes is available, although untested, is that the RC ratios for Rate 2/12 and Rate 3/13 should be in the range of 115%.

Under interim refundable rates, CCA suggested that if the Board were to conclude that the Rate 2/12 and 3/13 were paying rates in excess of existing rates, these customers will be fully refunded any excess revenues they pay between now and the final determination of the 2003/04 rates. CCA submitted that all AUI has effected is a situation where Rate 1 is used to fund the rate relief to Rates 2/12 and 3/13 on an interim basis. CCA argued that if the Company wishes to wrap up the 2002 Phase II, and address the concerns of the Rate 2/12 and 3/13 customers, it should provide interim funding on its own, without asking other customers for such financing.

CCA also submitted in all the meetings they attended that there was never unanimous consensus[4] that "Rates 2 and 3 might be paying more than their fair share of the costs".

5 VIEWS OF THE BOARD

The Board notes that AUI argued that the Application arose from settlement discussions with parties involved in AUI's 2000/2001/2002 Phase II GRA, whereby the majority of customer groups accepted that the untested evidence suggested Rates 2 and 3 customers might be paying more than their fair share of the costs. The Board agrees with the CCA that there was never unanimous consent that Rates 2 and 3 might be paying more than their fair share of the costs, however, that assertion was never argued by AltaGas in its application. The Board is satisfied that the majority of customer groups generally supported or did not contest the application, and that Rate 1 customers were well represented via other customer groups in addition to the CCA. The Board further notes that the CCA took no other issue with regards to AUI's October 6, 2003 reply submission.

The Board notes that AUI indicated that it proposed the interim refundable rates in response to PICA's request for relief to the customers served under Rates 2/12 and 3/13. The Board notes that only the CCA opposed the interim refundable rates, with no interested parties contesting the proposed harmonization of the Bonnyville Service Area's rates portion of the Application. The Board notes that the majority of the customers groups including those that represented Rate 1 customers supported the application.

The Board notes that the CCA submitted that the impact of AUI's proposed rate realignment increases rates for Rate 1/11 customers by a total of $209,800, with rate relief to Rate 2/12 of $58,000 and Rate 3/13 of $151,800. The Board considers that the financial consequence of AUI's application on Rate 1/11 customers is likely minimal when allocating the costs of the rate change of $209,800 against the total customer base of approximately 719,914.

While AUI attempts to directionally address PICA's concern, the Board notes that the CCA argued that the effect of the proposal is to worsen the RC ratio of the Rate 2/12. Effectively, the Board observes that the CCA asserted that while Rate 2/12 receive a small break from existing

[4] The CCA submission filed October 21, 2003, p. 1, the CCA stated that " In fact, at the September 26, 2003 meeting, the CCA representative made it clear that the proposal to have Rate 1 customers subsidize Rate 2/3 customers was unacceptable"

rates (from 126% to 120%), the RC ratio relative to what the Company would have filed as being appropriate in the 2002 COSS increases from 115% to 120%.

The Board considers that comparing the RC ratios for the interim refundable rates versus the proposed 2002 rates ignores the fact that AUI and its customers, including the CCA, reached a negotiated settlement on the 2000/2001/20002 rates, and accepted the continuation of existing rates as approved in Decisions U96116 and U98059. Therefore, the Board gives little weight to this argument.

The Board considers an RC ratio within a 5% tolerance limit of unity per rate class to be a reasonable objective, but recognizes that a cost of service study involves a certain degree of judgment, and rates that fall outside of this 95% to 105% range for the RC ratios of various rates may be also be appropriate. In Decision U96116, the Board stated that:

> In more recent decisions, the Board has also considered the revenue to cost ratios for the customer/demand/commodity components of the rates. Where rates or rate components have fallen outside this band, the Board has generally approved the rate if it constituted a move towards the band. This is in the interests of a degree of rate stability. Therefore, for rate classes where cost is the primary rate design criterion, the Board considers it appropriate to amend rate proposals that deviate significantly from cost. [5]

The Board agrees with AUI that the proposed interim refundable rates directionally address both the concerns of PICA and the Board objective of moving rates towards RC ratios within 5% of unity.

The Board also considers that the application only increases Rate 1/11 customers by a total of $209,800 with rate relief to Rate 2/12 of $58,000 and Rate 3/13 of $151,800. The Board recognizes that the RC ratio for Rate 1 customers increases from existing rates of 100.19% to 101.01% maintaining these rates well within the tolerance range of 5% from unity. The Board is of the view that as these rates are interim refundable, parties may raise any objections to the appropriateness of these rates in the 2003/2004 Phase II GRA proceeding. The Board does however agree with the CCA that although directionally correct, the interim refundable rates have not been tested against a cost of service study. Therefore, the Board directs AUI to file a 2004 cost of service study to allow the Board and interested parties an opportunity to evaluate the interim refundable rates before any final determinations of rates are made. The Board accepts AUI's interim refundable rates as filed, and they are approved effective December 1, 2003 (Appendix C- Rate Schedules).

With regards to the Bonnyville service area, the Board notes that AltaGas filed an application on May 22, 2003, requesting approval of interim refundable rates, and terms and conditions of service for the Bonnyville service area that would result in postage stamp rates. The Board notes that the rates would affect Rate 1 and Rate 2 customers and would be identical to those being used in the balance of the AltaGas service area, similar to the AUI's current application. The Board notes that in Decision 2003-052, the Board agreed with the submission of the Consumers' Coalition of Alberta that rate increases, then decreases, could result from the application, and therefore denied the application.

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[5] Decision U96116, p. 3, December 16. 1996. Centra Gas Alberta Inc. 1995/1996 General Rate Application-Phase II

The Board notes that several factors have changed since the Board denied AUI's May 22, 2003 application for harmonization of Bonnyville service area rates. Firstly, the Board notes that the CCA has not contested this application as opposed to AUI's previous postage stamp rate application that resulted in Decision 2003-052. Secondly, as AUI has forecasted revenue deficiencies in both test years, the Board considers its concern regarding rate volatility for rate 1 customers has diminished. The Board concludes that as no customers have contested the realignment of Bonnyville Service Area's rates, and that the harmonization of rates will provide relief to Rate 2/12 and 3/13 customers in the Bonnyville service area as those in other service areas, the harmonizing of Bonnyville Service Area's rates at this time is just and reasonable.

Therefore, for all of the above reasons, the Board hereby approves the Application.

6 ORDER

IT IS HEREBY ORDERED THAT:

(1) AltaGas Utilities Inc. interim refundable rates, as set out in Appendix C, are approved as filed, effective December 1, 2003, until such time as other rates are approved for AltaGas Utilities Inc. by the Board.

(2) Effective December 1, 2003, harmonization of rates for the Bonnyville District service area, as set out in the Application, are approved and are set at the same rates as the rest of the AltaGas Utilities Inc.'s service areas.

(3) The Board directs AltaGas Utilities Inc. to file a 2004 Cost of Service Study with its 2003/2004 Phase II General Rate Application.

Dated in Calgary, Alberta on November 25, 2003.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

R. G. Lock, P.Eng.
Presiding Member

(original signed by)

Gordon J. Miller
Board Member

(original signed by)

J. G. Gilmour
Acting Member

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2005-0020
EB-2005-0409

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an Application by PowerStream Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2006.

BEFORE: Paul Vlahos
Presiding Member

Bob Betts
Member

DECISION AND ORDER

PowerStream Inc. ("PowerStream" or the "Applicant") is a licensed distributor providing electrical service to consumers within its defined service area. PowerStream filed an application (the "Application") with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other matters, to be effective May 1, 2006.

PowerStream is one of over 90 electricity distributors in Ontario that are regulated by the Board. To streamline the process for the approval of distribution rates and charges for these distributors, the Board developed and issued the 2006 Electricity Distribution Rate Handbook (the "Handbook") and complementary spreadsheet-based models. These materials were developed after extensive public consultation with distributors, customer groups, public and environmental interest groups, and other interested parties. The Handbook contains requirements and guidelines for filing an application. The models determine the amounts to be included for the payments in lieu of taxes ("PILs") and calculate rates based on historical financial and other information entered by the distributor.

Also included in this process was a methodology and model for the final recovery of regulatory assets flowing from the Board's decision dated December 9, 2004 on the Review and Recovery of Regulatory Assets – Phase 2 for Toronto Hydro, London Hydro, Enersource Hydro Mississauga and Hydro One Networks Inc. ("Hydro One"). In Chapter 10 of the decision, the Board outlined a Phase 2 process for the remaining distributors. By letter of July 12, 2005, the Board provided guidance and a spreadsheet-based model to the distributors for the inclusion of this recovery as part of their 2006 distribution rate applications.

As a distributor that is embedded in Hydro One Network's low voltage system, the Applicant has included the recovery of certain Regulatory Assets that have been allocated by Hydro One Networks. The amount claimed by the Applicant was provided by Hydro One Networks as a reasonable approximation of the actual amount that Hydro One Networks will assess the Applicant. To the degree that the amount differs from the actual amount approved for Hydro One Networks in another proceeding (RP-2005-0020/EB-2005-0378), this difference will be reconciled at the end of the Regulatory Asset recovery period, as set out in the Phase II regulatory assets decision issued on December 9, 2004 (RP-2004-0064/RP-2004-0069/RP-2004-0100/RP-2004-0117/RP-2004-0118).

In its preliminary review of the 2006 rate applications received from the distributors, the Board identified several issues that appeared to be common to many or all of the distributors. As a result, the Board held a hearing (EB-2005-0529) to consider these issues (the "Generic Issues Proceeding") and released its decision (the "Generic Decision") on March 21, 2006. The rulings flowing from that Generic Decision apply to this Application, except to the extent noted in this Decision. The Board notes that pursuant to ss. 21 (6.1) of the *Ontario Energy Board Act, 1998*, and to the extent that it is pertinent to this Application, the evidentiary record of the Generic Issues Proceeding is part of the evidentiary record upon which the Board is basing this Decision.

In December 2001, the Board authorized the establishment of deferral accounts by the distributors related to the payments that the distributors make to the Ministry of Finance in lieu of taxes. The Board is required, under its enabling legislation, to make an order with respect to non-commodity deferral accounts once every twelve months. The Board has considered the information available with respect to these accounts and orders that the amounts recorded in the accounts will not be reflected in rates as part of the Rate Order that will result from this Decision. The Board will continue to monitor the accounts with a view to clearing them when appropriate.

Public notice of the rate Application made by PowerStream was given through newspaper publication in its service area. The evidence filed was made available to the public. Interested parties intervened in the proceeding. The evidence in the Application was tested through written interrogatories from Board staff and intervenors, and intervenors and PowerStream had the opportunity to file written argument. While the Board has considered the entire record in this proceeding, it has made reference in this Decision only to such evidence and argument as is necessary to provide context to its findings.

PowerStream has requested an amount of $91,651,268 as revenue to be recovered through distribution rates and charges. Included in this amount is a credit of $6,973,189 for the recovery of regulatory assets. Except where noted in this Decision, the Board finds that PowerStream has filed its Application in accordance with the Handbook and the guidelines for the recovery of regulatory assets.

Notwithstanding PowerStream's general compliance with the Handbook and associated models, in considering this Application the Board reviewed the following matters in detail:

- Low Voltage Rates;
- Tier 1 Revenue Adjustments;
- Tier 1 Cost of Power Adjustment;
- PILs Interest Adjustment;
- Rate Harmonization and Consolidation;
- Regulatory Assets;
- Transformation Assets;
- Specific Service Charges; and
- Consequences of the Generic Decision (EB-2005-0529).

Low Voltage Rates

PowerStream included in its Application recovery of ongoing Low Voltage ("LV") charges that Hydro One Networks will be levying on PowerStream for Low Voltage wheeling distribution services provided to PowerStream.

PowerStream stated in its Application that it has adjusted distribution expenses by $879,693 to reflect the amount that it expects to pay Hydro One for LV service after May 1, 2006 and that this amount is calculated using 4 months of 2004 demand data and 8 months of 2005 data. However, the Handbook states that the embedded distributor's 2004 consumption levels should be used and, consequently, PowerStream's approach represents a departure from the Handbook.

PowerStream stated that this has been done since "the data for the first eight months of 2004 reflect a metering configuration that is different from the present configuration." In response to a Board staff interrogatory requesting the quantification of the impact of applying this methodology versus that specified in the Handbook, PowerStream noted that recovery would be reduced by $153,347.

The Board is of the view that the Handbook should be followed unless there is a compelling reason for doing otherwise. Powerstream's reasons for requesting the variation have not been sufficiently compelling, particularly in light of the deferral account handling of the LV charges, and the opportunity to track and "true-up" the LV costs charged by the host distributor and corresponding revenues recovered from ratepayers. Accordingly, the Board has adjusted PowerStream's low voltage recovery amount to conform to the approach outlined in the Handbook.

The estimate of PowerStream's low voltage expenses reflects Hydro One Networks' current approved LV rate of $0.56/kW. Hydro One Networks applied for an LV rate of $0.63/kW in its 2006 rate application RP-2005-0020/EB-2005-0378, and the Board has approved this rate. Recognizing that apparent difference, and in an effort to avoid systemic sources of variance, the Board will adjust Powerstream's rates to reflect the LV rates authorized by the Board for the host distributor. Accordingly, the Board has further revised the amount for LV charge recovery in PowerStream's revenue requirement.

Tier 1 Revenue Adjustments

PowerStream includes in the model a series of Tier 1 Revenue adjustments. These adjustments total $6,721,921 and are listed below:

Other Electric Revenue	$ 253,559
Misc. Service Revenue	$ 827,000
Misc. Non-Op Revenue	$ 758,493
Rate Payer Benefit Inc. Int.	$ 145,600
Interest & Div. Inc.	$4,737,269
Total	$6,721,921

PowerStream stated that the adjustment to Other Electric Revenue of $253,559 is related to revenue that was received in 2004 from a feeder for which charges were billed from Richmond Hill Hydro to Markham Hydro and which were no longer charged once PowerStream was created. The Board is not persuaded that this adjustment is necessary since PowerStream's filing is based on consolidated data and this amount should be subject to inter-corporate elimination upon consolidation. PowerStream's evidence has not provided a clear justification for this adjustment. Therefore, the Board does not accept the proposed adjustment and has removed it from the Applicant's model.

Regarding the adjustment to Miscellaneous Service Revenue of $827,000, PowerStream stated that it is related to revenue received by Hydro Vaughan for the Vaughan Mills project which will not continue to be received in 2006. The Board is concerned that this adjustment is an example of selective ratemaking, and represents a quasi-forward test year approach that is not appropriate for an historical test year application. The Handbook permits, and in some instances requires, adjustments to be made for specific items in 2004 that were unusual, in the context of an historical test year application. However, such allowance does not extend to making selective adjustments which effectively constitute a piecemeal forward test year approach. PowerStream had the option to file a forward test year application but chose not to.

A further reason for this finding is that PowerStream has not demonstrated that the Vaughan Mills project is out of character for its ongoing business and that similar projects may not occur in the future. In addition, there is no evidence that PowerStream has made any corresponding adjustments to remove expenses related to this revenue. For these reasons, the Board does not accept this adjustment and has removed it from the Applicant's model.

With respect to the adjustment to Miscellaneous Non-operating Revenue of $758,493 PowerStream stated that it consisted of three items, which are: (1) $531,000 related to a one-time payment from developers for lost or damaged fibreglass construction stakes; (2) $100,000 one-time credit received by Richmond Hill Hydro from a supplier, and (3) $127,493 administrative fee formerly charged by Markham Hydro for repairing damaged utility property. With respect to the administrative charge levied by Markham Hydro, PowerStream has not provided enough information to demonstrate that this revenue loss is not compensated for elsewhere through specific service charges. In any event, both the supplier credit and the administrative fee appear to be piecemeal forward adjustments which are not appropriate for an historical test year application. The Board has adjusted the Applicant's model to reflect these findings.

The Board is of the view that the component of the adjustment related to the one-time payment from developers for lost or damaged fibreglass construction stakes may be appropriate. However, the Board is concerned about the apparent absence of a corresponding removal of related costs. Accordingly, the Board deems and allows 50% of this adjustment. The Board has adjusted the Applicant's model to reflect this finding.

PowerStream has made an adjustment under 'Rate-payer Benefit Including Interest' of $145,600. This adjustment is comprised of administrative fees levied by Hydro Vaughan for service restorations and repairs to correct power diversions, which as a result of a review and correspondence with the Board's Compliance Office were discontinued. The Board considers this an appropriate adjustment and will allow it.

PowerStream has also made an adjustment to interest and dividend income in the amount of $4,737,269, consisting of two components. The first relates to interest earned on regulatory asset balances, which PowerStream claims will not be earned in the future. The second is recovery of $2,357,942 because PowerStream claims that it will no longer maintain excess cash balances to meet short-term cash requirements and will, accordingly, generate less income in future years.

Regarding PowerStream's adjustment related to the regulatory asset accounts, the Board finds that the Applicant has provided insufficient evidence to justify this adjustment. The adjustment appears selective and relates only to interest on three of the regulatory asset accounts. Accordingly, the Board will not allow the adjustment on the basis of the information provided. The Board has adjusted the Applicant's model to remove this adjustment.

The Board is of the view that the component related to lost interest on cash balances represents an adjustment more appropriate to the scope of a future test year application and, accordingly, will not allow it. The Board has adjusted the Applicant's model to reflect this finding.

Tier 1 Cost of Power Adjustment

PowerStream has included in its Application a total adjustment to working capital of $1,075,129. Of this amount, $451,764 is related to the Cost of Power ("COP") adjustment referenced in the Handbook, and this portion of the adjustment is accepted by the Board.

PowerStream stated that the remaining $623,364 is due to the COP in its 2004 trial balance being the energy amount billed to customers by PowerStream, rather than PowerStream's actual COP.

PowerStream further explained that "in accordance with Article 490 during the year, PowerStream books the costs associated with purchasing power to the trial balance. This amount equals the IESO invoices. In order to ensure that the COP is a pass through PowerStream reviews the total cost versus the total energy billed and the appropriate RSVA adjustment is made."

The Board does not accept this adjustment. The Board is of the view that a consistent approach to an adjustment of this kind would require that it be undertaken for 2002, 2003 and 2004 and then averaged, as is the case for the COP adjustment outlined on page 33 of the Handbook. Additionally, such adjustments would involve all of the RSVA accounts. Accordingly, the Board has adjusted the Applicant's model to remove this adjustment amount of $623,364.

PILs Interest Adjustment

In determining the amount of its PILs recovery, PowerStream removed $1,775,178 of 2004 interest expense on the basis that this expense was higher than would be expected in a typical year due to the presence of four non-typical factors, which were:

Reduced carrying charges due to reduction in over-recovery of transmission connection expenses	$ 885,449
Elimination of $25 million in Richmond Hill notes	$ 638,206
Customer deposit interest expense offset by the interest earned on customer deposits	$ 206,523
Fee to arrange increased line of credit to support the formation of PowerStream	$ 45,000
Total	$ 1,775,178

These are in the Board's view adjustments that are akin to a future test year review and not in compliance with Section 7.2.6 of the Handbook. Accordingly, the Board does not accept the adjustments and has revised the Applicant's models to remove them.

Rate Harmonization and Consolidation

The Town of Richmond Hill ("Richmond Hill") intervened in this proceeding to stress the importance of PowerStream honouring the commitments made to harmonize electricity distribution rates, so that Richmond Hill customers would not continue to pay significantly higher rates than Markham and Vaughan customers.

Richmond Hill submitted that a "harmonization plan should be brought forward independently of any cost allocation plan in the event that the Board determines that it will not require PowerStream to make any cost allocation-related adjustments in 2007." Richmond Hill further submitted that "the Board has the authority and discretion to direct an applicant to bring materials forward in subsequent rate cases."

In reply, PowerStream submitted that there was "no new information or change in circumstances that support such a course of action," and in any event there was no need for the Board to make the requested direction since "PowerStream has already unequivocally committed to prepare and prosecute an application to the Board seeking approval of distribution rates for 2007, fully harmonized across PowerStream's entire service area, on the basis of a system-wide cost allocation study."

The School Energy Coalition supported PowerStream's decision not to propose rate harmonization in the 2006 application on the basis that "Schools is a strong supporter of the use of properly conducted cost allocation studies for determining rates."

The Board is concerned about the rate disparities that continue to exist between PowerStream's Richmond Hill and other customers, especially given the time that has elapsed since the acquisition of Richmond Hill Hydro by PowerStream's predecessor companies.

The Board notes the specific commitment PowerStream has made, quoted above, and directs PowerStream to meet this commitment and bring forward a proposed harmonization plan to allow for the implementation of harmonized rates in 2007. Such a harmonization plan is required to be filed regardless of whether the cost allocation information is available.

Regulatory Assets

The Board notes that PowerStream has used "number of customers" as the allocator to dispose of the balance in Regulatory Asset Account 1508, even though the Board's letter of July 25, 2005 had suggested distribution revenue as the appropriate allocator.

PowerStream stated that using number of customers as the allocator "is consistent with the objective of providing an adequate level of consumer protection to each consumer, regardless of that customer's consumption. This ensures that the level of consumer protection afforded to each customer is not tied to the revenue that such customer contributes."
The Board is of the view that a consistent approach to this adjustment should be applied across all applications and, accordingly, has adjusted PowerStream's application to reflect the use of distribution revenue as the allocator for Account 1508.

Transformation Assets

Some assets operated by a distributor may be classified as part of a transmission system according to the definition of "transmission system" in the *Ontario Energy Board Act, 1998.* The Board has the power, under section 84 of the Act, to determine that transmission system assets are part of a distribution system, and can therefore treat them as distribution assets for the purpose of setting distribution rates.

The Board notes that there is an issue as to whether or not certain transformer station equipment owned by PowerStream and recorded in the transformer station equipment account requires such a determination to be made by the Board.

PowerStream did not request any such determination in its original application and in response to a Board staff interrogatory stated that: "PowerStream confirms that it is not including any assets in the distribution rate base that would not be included in the definition of the distribution rate base, other than those that have been deemed to be distribution assets under section 84 (a) of the *OEB Act, 1998,* in the Director of Licensing's Decisions of October 2000."

The Board is concerned that the subject assets might be classified as transformation assets under the *Ontario Energy Board Act, 1998*, despite the fact they are part of PowerStream's distribution system. Accordingly, the Board deems the transformation assets to be distribution assets.

Specific Service Charges

PowerStream requested in its Application two Specific Service Charges which departed from the standard charges specified in the Handbook.

In Section 11.1 of its Application, PowerStream stated that where the Board has established standard charges, it charged the standard amounts. However, PowerStream provides two services for which there is no standard Board-approved charge: final bill issue ($10) and reference letter ($15) and proposed to continue these charges. PowerStream stated that these charges had been approved by the Board for its three predecessor utilities.

PowerStream subsequently stated that upon further review, both these charges could be accommodated within the Board's standard charges.

The Board wishes to see continued movement toward uniformity in provincial electricity rates and that the rates applied reasonably match the cost of services rendered. The Board is charged with the responsibility of ensuring that cross subsidization of services is minimized to the extent practicable. The Board has therefore revised the Applicant's standard service charges, and directs the Applicant to apply these charges as stated in the Tariff of Rates and Charges. In making this finding, the Board concluded that there should not be an undue impact on customers using these services.

Consequences of the Generic Decision on this Application

The Generic Decision contains findings relevant to funding for smart meters for electricity distributors. The Applicant did not file a specific smart meter investment plan or request approval of any associated amount in revenue requirement. Absent a specific plan or discrete revenue requirement, the Generic Decision provides that $0.30 per residential customer per month be reflected in the Applicant's revenue requirement. The Board finds that this increase in the revenue requirement amount will be allocated equally to all metered customers and recovered through their monthly service charge. This increment is reflected in the approved monthly service charges contained in the Tariff of Rates and Charges appended to this Decision. Pursuant to the Generic Decision, a variance account will be established, the details of which will be communicated in due course.

Resulting Revenue Requirement

As a result of the Board's determinations on these issues, the Board has adjusted the revenue requirement to be recovered through distribution rates and charges to $84,503,381, including a credit amount of $6,973,189 for the recovery of Regulatory Assets.

In its letter of December 20, 2004 to electricity distributors, the Board indicated that it would consider the disposition of the 2005 OEB dues recorded in Account 1508 in this proceeding. However, given that the final 2005 OEB dues are not available because of the difference in fiscal years for the Board and the distributors, and given that the model used to develop the Application does not incorporate this provision, the Board will review and dispose of the 2005 OEB dues at a later time.

Cost Awards

This Application is one of a number of applications before the Board dealing with 2006 rates chargeable by distributors. Intervenors may be parties to multiple applications and, if eligible, their costs associated with a specific distributor may not be separable. Therefore, for these applications, the matter of intervenor cost awards will be addressed by the Board at a later date, upon the conclusion of the current rate applications. If an intervenor that is eligible to recover its costs is able to uniquely identify its costs associated with this Application, it must file its cost claim within 10 days from the receipt of this Decision.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix "A" of this Order is approved, effective May 1, 2006, for electricity consumed or estimated to have been consumed on and after May 1, 2006. The application of the revised distribution rates shall be prorated to May 1, 2006. If PowerStream Inc.'s billing system is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors shall be implemented upon the first subsequent billing for each billing cycle.

2. The Tariff of Rates and Charges set out in Appendix "A" of this Order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for PowerStream Inc., and is final in all respects.

3. PowerStream Inc. shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 28, 2006.

ONTARIO ENERGY BOARD

P. O'Dell

Peter H. O'Dell
Assistant Board Secretary

Appendix "A"

RP-2005-0020
EB-2005-0409

April 28, 2006

ONTARIO ENERGY BOARD

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RP-2005-0020
EB-2005-0409

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2006 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2006 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2006 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall be classified as general service.

General Service Less Than 50 kW
This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 4,999 kW
This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW.

General Service 50 to 4,999 kW – Time of Use
This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Usage is measured by a time of use meter, which is a device that measures and records electrical usage during pre-specified periods of the day cumulatively over a meter reading period.

Large Use
This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW.

Unmetered Scattered Load
This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load.

Sentinel Lighting
This classification refers to an unmetered lighting load supplied to a sentinel light.

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Street Lighting
This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

MONTHLY RATES AND CHARGES

Markham Rate Zone

Residential

Service Charge	$	10.46
Distribution Volumetric Rate	$/kWh	0.0121
Regulatory Asset Recovery	$/kWh	(0.0007)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0027
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service Less Than 50 kW

Service Charge	$	27.10
Distribution Volumetric Rate	$/kWh	0.0084
Regulatory Asset Recovery	$/kWh	(0.0012)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0025
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	303.38
Distribution Volumetric Rate	$/kW	1.3530
Regulatory Asset Recovery	$/kW	(0.3898)
Retail Transmission Rate – Network Service Rate	$/kW	2.1855
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9808
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

General Service 50 – 4,999 kW – Time of Use

Service Charge	$	2,573.78
Distribution Volumetric Rate	$/kW	1.2830
Regulatory Asset Recovery	$/kW	(0.9205)
Retail Transmission Rate – Network Service Rate	$/kW	2.3211
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0751
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

PowerStream Inc.
TARIFF OF RATES AND CHARGES
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Unmetered Scattered Load

Service Charge (per customer)	$	26.83
Distribution Volumetric Rate	$/kWh	0.0084
Regulatory Asset Recovery	$/kWh	(0.0012)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0025
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge	$	0.56
Distribution Volumetric Rate	$/kW	1.4323
Regulatory Asset Recovery	$/kW	0.7657
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.6565
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	0.7740
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.20
Distribution Volumetric Rate	$/kW	1.3526
Regulatory Asset Recovery	$/kW	(0.7320)
Retail Transmission Rate – Network Service Rate	$/kW	1.6482
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7582
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Richmond Hill Rate Zone

Residential

Service Charge	$	12.35
Distribution Volumetric Rate	$/kWh	0.0140
Regulatory Asset Recovery	$/kWh	(0.0010)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0027
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service Less Than 50 kW

Service Charge	$	31.61
Distribution Volumetric Rate	$/kWh	0.0118
Regulatory Asset Recovery	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0025
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RP-2005-0020
EB-2005-0409

General Service 50 to 4,999 kW

Service Charge	$	278.99
Distribution Volumetric Rate	$/kW	3.0582
Regulatory Asset Recovery	$/kW	(0.0082)
Retail Transmission Rate – Network Service Rate	$/kW	2.1855
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9808
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	15.67
Distribution Volumetric Rate	$/kWh	0.0118
Regulatory Asset Recovery	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0025
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.79
Distribution Volumetric Rate	$/kW	4.4808
Regulatory Asset Recovery	$/kW	(0.8406)
Retail Transmission Rate – Network Service Rate	$/kW	1.6482
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7582
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Vaughan Rate Zone

Residential

Service Charge	$	11.21
Distribution Volumetric Rate	$/kWh	0.0105
Regulatory Asset Recovery	$/kWh	(0.0017)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0027
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service Less Than 50 kW

Service Charge	$	26.72
Distribution Volumetric Rate	$/kWh	0.0135
Regulatory Asset Recovery	$/kWh	(0.0022)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0025
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

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RP-2005-0020
EB-2005-0409

General Service 50 to 4,999 kW

Service Charge	$	290.79
Distribution Volumetric Rate	$/kW	2.6462
Regulatory Asset Recovery	$/kW	(0.4488)
Retail Transmission Rate – Network Service Rate	$/kW	2.1855
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9808
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Large Use

Service Charge	$	7,718.58
Distribution Volumetric Rate	$/kW	1.1148
Regulatory Asset Recovery	$/kW	(0.9271)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.5701
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.2295
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	13.23
Distribution Volumetric Rate	$/kWh	0.0135
Regulatory Asset Recovery	$/kWh	(0.0022)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0025
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge	$	0.50
Distribution Volumetric Rate	$/kW	2.0430
Regulatory Asset Recovery	$/kW	0.4220
Retail Transmission Rate – Network Service Rate	$/kW	1.6565
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7740
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.90
Distribution Volumetric Rate	$/kW	3.6890
Regulatory Asset Recovery	$/kW	(1.3390)
Retail Transmission Rate – Network Service Rate	$/kW	1.6482
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7582
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RP-2005-0020
EB-2005-0409

Specific Service Charges – All Rate Zones

Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charges - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charges - At Meter After Hours	$	185.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0393
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0289
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2008-0222
EB-2008-0223

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF applications by Canadian Niagara Power Inc. – Eastern Ontario Power, Canadian Niagara Power Inc. – Fort Erie for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2009.

BEFORE: Paul Vlahos
Presiding Member

Ken Quesnelle
Member

DECISION
July 15, 2009

INTRODUCTION

Canadian Niagara Power Inc. ("CNPI") is a wholly-owned subsidiary of FortisOntario Inc. CNPI owns and operates distribution businesses in the following three territories; Fort Erie, Port Colborne and Gananoque (or Eastern Ontario Power). Currently the three service areas have separate rates.

CNPI submitted a separate rate application for each of these service territories and the Board gave them file numbers as follows:

- CNPI – Eastern Ontario Power EB-2008-0222,
- CNPI – Fort Erie EB-2008-0223, and
- CNPI – Port Colborne EB-2008-0224.

While the applications are separate, because they have been prepared by CNPI and contain some common elements and the intervenors are the same, the Board decided to deal with all three applications at the same time. However, as the evidentiary phase for the Port Colborne application has not concluded, this decision pertains to only the Fort Erie and Eastern Ontario Power ("EOP") applications. The issuance of these two decisions now will reduce the impact of retroactive rate increases for the affected customers.

The intervenors of record for all three applications are: the Association of Major Power Consumers in Ontario ("AMPCO"), Energy Probe Research Foundation ("Energy Probe"), the School Energy Coalition ("SEC") and the Vulnerable Energy Consumers Coalition ("VECC"). AMPCO was not active in these proceedings.

Fort Erie supplies electricity to approximately 16,000 customers. Its service territory is mainly the Town of Fort Erie. The Fort Erie application is seeking approval of $9,827,418 as the 2009 revenue requirement.

EOP supplies electricity to approximately 3,650 customers. Its service territory includes the Town of Gananoque and some parts of the Township of Leeds and the Thousand Islands, of the Township of Frontenac Islands and of the City of Kingston. The EOP application is seeking approval of $2,359,739 as the 2009 revenue requirement. The EOP application also seeks approval to eliminate the current General Service 50 to

4,999 kW – Time of Use class, in accordance with a previous Board decision (EB-2007-0594), and to re-classify any customers in that class to the General Service 50 to 4,999 kW class.

The applications include a proposed harmonization of rates for the Fort Erie and EOP service areas with the exception of certain aspects that are specific to each service area, such as loss adjustment factors, transmission service rates and low voltage costs recovery. There is no harmonization proposed for Port Colborne.

The evidentiary phase of the Fort Erie and EOP applications concluded at the end of the oral hearing on April 23, 2009 and the filing of undertakings on April 30, 2009. CNPI filed an Argument-in-Chief on the two applications on May 14, 2009. Submissions by intervenors and Board staff were received by May 29, 2009 and Reply Argument was received on June 15, 2009.

The full record of the proceeding is available at the Board's offices. The Board has summarized the record in this Decision only to the extent necessary to provide context for its findings.

CAPITAL EXPENDITURES

The table below shows the proposed capital expenditures for Fort Erie and EOP for 2009 and compares them with prior years.

Capital Expenditures (excluding Smart Meters)

	2006 Actual	2007 Actual	2008 Bridge	2009 Test
CNPI – Fort Erie	$3,949,000	$4,501,000	$4,139,000	$4,110,000
CNPI – EOP	$264,000	$2,798,000	$967,000	$868,000

Board staff and VECC did not take issue with CNPI's proposed capital expenditures for the 2009 Test Year in either service area.

SEC stated that the Board does not have the context to assess the value of CNPI's capital investment as CNPI had an opportunity to provide its business plan and declined to do so. SEC submitted that the Board should compel CNPI to file with the Board its current long term business plan, with all narrative, and with all back up analysis, prior to the end of this year. SEC noted that this would not affect current rates but rather provide the Board increased visibility on CNPI and assist the Board in future CNPI cost-of-service rate applications.

CNPI responded that it has filed its business plans. This matter was specifically addressed in the SEC's motion on March 12, 2009, where the Board rejected the SEC's request to compel CNPI to provide additional information.

Energy Probe noted that CNPI considers age as the primary factor for replacing cables and argued that, although replacement of aging cables may be necessary, it is not apparent from the evidence that age is a reliable proxy for cable condition. Rather, diagnostic testing would provide a more objective basis for assessing the actual condition of distribution plant with age being used as one factor for selecting the plant to be tested. Energy Probe submitted that CNPI should provide diagnostic testing in future rate applications to support plant replacement rather than rely on age of the plant as the principal criterion.

CNPI responded that diagnostic testing can be very expensive and results are probability based. In a smaller utility like CNPI, with limited underground assets, it is unlikely there will be sufficient test results available to build a dependable database on which to draw probabilistic conclusions. CNPI also stated that its visual inspections, required by the *Distribution System Code*, combined with past operating experience are a reasonable approach for prioritizing future plant replacement.

CNPI has included capital expenditures to improve the load carrying capacity of the circuits feeding downtown Gananoque at a projected cost of $100,000. Energy Probe noted that, in cross examination, CNPI’s witness acknowledged that the Gananoque load carried by this feeder has declined since its peak of 14 MW in the summer of 2008 to a forecast peak of 11 MW in 2009. Energy Probe noted that, according to the witness, the East side line described in this project is probably capable of carrying the 11 MW load that is now forecast for the downtown Gananoque area. Energy Probe submitted that, because this line is only required to carry the entire downtown load under contingency conditions (i.e. when the West line is out of service) and because the line is capable of carrying the current forecasted load, this project should be postponed until such time as it becomes necessary.

CNPI responded that Energy Probe assumes that the East line conductors, connectors and ancillary line equipment have not lost any of their current carrying capacity over their life. Good utility practice suggests that the utility will recognize weaknesses in the distribution system and take action to address those weaknesses in order to avoid jeopardizing the integrity of the system and provide reliable service. EOP has recognized a weakness associated with the East line and has implemented a plan to address that weakness. Energy Probe's submission that EOP defer the project until it is necessary (presumably when the line can no longer support the load) is not a reasonable solution and will unnecessarily expose the residents and customers of Gananoque to power outages.

Board Findings

SEC asked the Board to compel CNPI to file with the Board its current long term business plan, with all narrative, and with all back up analysis, prior to the end of this year. This, in the Board's view would be inconsistent with, and in fact contrary to, the Board's normal processes and expectations by the stakeholder community generally. The purpose of this proceeding is to rebase rates for the duration of the current IRM plan based on 2009 as the test year. The Board is doing so on the evidence adduced, which included the filing of available business plans from CNPI, and having considered motions regarding the production of additional information. SEC is in fact rearguing what it had already argued in its March 12 motion before the oral hearing, in which it was not successful. The Board sees no compelling reasons to make the direction suggested by SEC.

Energy Probe has not suggested that any adjustment be made by the Board to the proposed capital expenditures for cable replacement for Fort Erie, and the Board will not make any adjustments. The Board is satisfied on the evidence that the proposed cable replacement is a reasonable undertaking as other cables at the same station (Station 12) and of the same vintage were replaced in 2000 or 2001 due to failures.

Energy Probe suggests that CNPI should provide diagnostic testing in future rate applications to support plant replacement rather than rely on age of the plant as the principal criterion. The Board is not prepared to make such blanket direction in this case for the reasons cited by CNPI. Specifically, CNPI has indicated that it has considered the potential benefits of more analytical testing procedures and has determined it may not be fruitful in their situation given the relatively small groupings of common assets. The Board accepts this rationale.

For the reasons cited by CNPI, the Board is not convinced by Energy Probe's argument that the capital expenditures to improve the load carrying capacity of the circuits feeding downtown Gananoque should be postponed. CNPI's capital expenditures are in line with historic spending and are primarily driven by sustaining and enhancement initiatives. A tenet of sound asset management is to smooth out the replacement of aging assets over time in a manner that seeks to optimize the useful life of the assets as well as well as their serviceability. CNPI's approach is consistent with this desirable methodology in that it has prioritized its sustaining/enhancement projects in such a way as to consider both the need to smooth its capital spending and optimize the useful life of the assets while timing their replacement in anticipation of a capacity shortfall. All three elements of this methodology must be considered in balance. Energy Probe's suggested approach places too high an importance on the capacity element which if applied to all system components would result in unmanageable peaks and valleys of construction and spending activity.

WORKING CAPITAL ALLOWANCE (WCA)

CNPI has used the standard methodology of calculating the WCA as 15% of the sum of controllable expenses and the cost of power. CNPI has documented that the WCA differs for all three of the service area applications depending on circumstances. For example, Fort Erie is not embedded to Hydro One Networks, and so LV charges do not factor into the determination of its WCA. CNPI has noted that it used the RPP price of $0.0545/kWh from the April 11, 2008 Regulated Price Plan Report of the Board to proxy the commodity price, and used RTS and Wholesale Market Charges from the Board's April 21, 2008 Rate Order, in determining the Cost of Power.

No party took issue with the methodology of determining WCA. Parties noted the need to update certain inputs in calculating the final WCA value, and CNPI agreed.

Board Findings

The Board notes that there is concurrence by all parties on this issue. Consistent with the Board's policy and practice, the Board agrees that, for the purposes of determining CNPI's 2009 distribution rates, the working capital allowance would be updated to reflect the current Board-approved transmission rates and the most current RPP commodity estimate available, namely $0.06072/kWh, from the Board's Regulated Price Plan Report of April 15, 2009.

The Board directs CNPI to submit with the draft rate order an updated Exhibit 2, Tab 4, Schedules 1 and 2, for each of the Fort Erie and EOP service areas, as support for that recalculation. CNPI should identify the commodity, RTS, Wholesale Market Service Charge and other applicable rates used in the Cost of Power update. The updated schedule shall also include any changes as the Board determines elsewhere in this decision.

LOAD FORECAST

CNPI used a combination of weather normalization work completed by Hydro One Networks and more current data from the Ontario Demand Forecast produced by the IESO.

Hydro One Networks had determined the relative percentages of distribution system loads that are sensitive and non-sensitive to influences of weather. The IESO had developed a measure of the effect of weather on the Ontario Loads. CNPI combined the two factors creating "uplift factors" that were used to proxy the impact of weather on its historic loads and to develop weather adjusted forecasts.

CNPI analyzed the microeconomics of both Gananoque and Fort Erie in order to produce its customer forecasts for the two communities. The parties did not raise any issues related to CNPI's customer forecasts. Some parties raised a number of concerns with CNPI's load forecast methodology and this section deals with those.

The following tables provide a summary of the actual, normalized actual and forecasted throughput volumes for the 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test year for each service area.

CNPI – Fort Erie Volumes (kWh)

2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
304,511,490	287,341,134	297,196,138	299,924,558	304,156,931

CNPI – EOP Volumes (kWh)

2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
85,815,078	75,398,070	66,086,052	65,252,488	62,979,630

Despite some reservations that related to weather normalization correction factor and to a lesser extend the future CDM effects, Board staff submitted that the load forecasts are reasonable.

VECC, supported by SEC, noted that the IESO weather normalization methodology captures the weather impacts across the entire province and, in doing so, reflects weather conditions and the amount of weather sensitive load across the entire province. As a result, the factor is not representative of either Fort Erie's or EOP's service area. Indeed, CNPI acknowledged this point during the oral phase of the proceeding. VECC also noted that the specific adjustment factor developed for each service area (i.e., the ratio of total load to weather sensitive load) is problematic. The definition of "weather sensitive" load assumes that all residential and GS<50 class loads are weather sensitive when this is readily acknowledged as not being the case. Also, the factor works such that the higher the portion of weather sensitive load the lower the weather normalization adjustment, which is a counter intuitive result. Finally, CNPI has acknowledged this factor does not correct for the fact the IESO adjusts for weather conditions that are different than those in CNPI's service areas.

VECC submitted the Board should encourage CNPI to improve its load forecast methodology and noted that a number of electricity distributors have developed load forecast methodologies that utilize load conditions to produce weather normalized results.

With respect to the results, VECC noted that when comparing historical usage with forecast usage one would expect the historical values to be both higher and lower due to annual weather conditions. However, with respect to Fort Erie, VECC argued that the forecast average use values for 2008 and 2009 are too low. For the Residential class the historical results are higher than the projected average use except for two years (2004 and 2006) and in one of the two the difference is less than 0.2%. Similarly, for the GS>50 class, the historical results are less than the forecast for 5 out of the 6 years and for the one year where there is an exception the difference is only 0.6%. For the GS<50 class the projected average use is less than that in any of the previous six historical years. In VECC's view the main reason for this is the flawed weather normalization methodology used by CNPI. VECC recommended that, at a minimum, the Board should direct CNPI to drop the utility-specific adjustment factor and rely only on the IESO adjustment factor. VECC argued that the utility-specific adjustment factor yields counter-intuitive results and does not properly adjust for service area specific conditions.

However, in VECC's view, given the acknowledged shortcomings of the IESO factor, a preferable approach would be to adopt the 6 year average historical per customer use value for each class as the basis for forecasting 2008 and 2009 volumes.

With respect to the results for EOP, VECC submitted that based on the historical data the forecast average use values for the Residential are reasonable. However, the GS<50 and GS>50 (Regular) values used for 2009 are too low. For the GS<50 class and the GS>50 (Regular) class, the proposed 2009 average use values are less than average use values in any of the previous 6 years. Similar to Fort Erie, in VECC's view the main reason for this is the flawed weather normalization methodology used by CNPI. Again, at a minimum VECC recommended that the Board should direct CNPI to drop the utility-specific adjustment factor and rely only on the IESO adjustment factor for the reasons outlined above. However, in a similar manner as outlined above, in VECC's view, a preferable approach would be to adopt the 5 year average historical per customer use value for each class as the basis for forecasting 2009 volumes. The use of a 5 as opposed to 6 year average is based on the cited problems with the 2002 and 2003 data.

CNPI responded to VECC's submissions as follows.

- CNPI's weather normalization methodology was based on the published IESO weather normalization factors which were modified by service area specific "uplift factors" determined from the ratio of weather sensitive and non-weather sensitive loads as determined by Hydro One Networks Inc. on CNPI's behalf in the 2006 Cost Allocation Filing.
- The results were intuitively reliable because they are based on actual data and are reflective of the historical results that CNPI has observed.

- CNPI incorporated the effects of CDM into its load forecasting by projecting previously realized CDM impacts into the Test Year forecast.
- While VECC's proposal may appear reasonable on the surface, it does not take into account the extensive review that CNPI had provided in its applications to compensate for the first-hand familiarity CNPI has with its customers. CNPI provided the Board with a thorough understanding of the communities serviced and the customer classes and CNPI's load forecast is a function of this knowledge and experience.

Board Findings

The parties that commented on CNPI's customer forecast submitted that they were reasonable and the Board accepts CNPI's proposed customer count.

The remaining issue of substance is the appropriateness of the use of the "uplift factors" that have been devised by CNPI to compensate for the variance between the IESO's correction factor and the local ratios between weather sensitive and non-sensitive loads as determined by Hydro One.

The hypothetical mathematical scenarios posited by VECC in its examination of the evidence were readily agreed to by CNPI. There is no dispute regarding the unsuitability of CNPI's methodology if one were to exchange the data used for the theoretical data in the illustrative example presented by VECC.

The Board is not convinced that the approaches suggested by VECC would produce results that are preferable to the one proposed by CNPI. CNPI has attempted to produce projections based on its empirical analysis of local results. The combination of relatively stable historic trends and CNPI's careful analysis of the historic results provides the Board with sufficient confidence to utilize the results of CNPI's methodology to determine load forecasts in this application for rate making purposes.

OM&A COSTS

The table below sets out the proposed OM&A costs for the test year for Fort Erie and EOP and compares them with prior years.

OM&A Costs

	2006 Actual	2007 Actual	2008 Bridge	2009 Test
CNPI – Fort Erie	$1,356,505	$914,403	$791,762	$841,410
CNPI – EOP	$286,543	$211,361	$234,418	$250,755

The Board deals below with the following issues:

- Sharing of Common Costs
- Vegetation Management Costs
- Control Room Costs
- Regulatory Costs
- OM&A Cost Benchmarking

Sharing of Common Costs

Within CNPI, management and specialist staff and certain key systems and facilities are shared among three service areas and with the transmission function. CNPI retained BDR NorthAmerica Inc. ("BDR") to review the methodology and computations used for the allocation of shared costs. This report (the "BDR Report") was filed as part of the evidence. The BDR Report confirms BDR's opinion as to the reasonableness of the overall approach by CNPI and the specific allocation of each cost function.

No party opposed the methodology or results of the study.

Board Findings

The Board accepts the overall approach in allocating common costs and the specific allocation of each cost function to Fort Erie and EOP as reasonable.

Vegetation Management

VECC noted that the 2009 vegetation management costs for Fort Erie includes a one-time cost increase of $68,608 and submitted that this amount should be levelized over the four year IRM period rather than embedded in 2009 base rates. In response, CNPI noted that it will have to return before the Board in three years to address the Port Colborne lease and therefore its IRM period would be three years.

EOP has a three year cycle for vegetation management. Board staff invited EOP to comment on the reasonableness of the three year cycle when a neighbouring utility, Hydro One Networks, uses an eight year cycle. CNPI responded that it is difficult to comment on Hydro One Networks' vegetation management program without understanding their operating strategy. Because of the inherent operational differences, a straight comparison of EOP and Hydro One Networks is difficult to assess.

Board Findings

The Board agrees with VECC that it is appropriate to amortize the one-time costs of $68,608 for Fort Erie. The Board reduces the OM&A costs in this regard by $45,738 to $22,870 for the purposes of setting 2009 rates to reflect the expectation that the CNPI's rates will be rebased after three years.

At the next rate rebasing, the Board expects CNPI to file appropriate evidence as to the reasonableness of the vegetation management cycle it plans to use going forward.

Control Room Costs

CNPI operates a 5 day 15 hour control room in the Fort Erie distribution territory. The main duties of control room operators are monitoring and operating the SCADA system and directing the switching and work protection activities of line staff working on the distribution system.

Energy Probe noted the evidence that the number of incidents per year that occur during evening shifts that require an operator to manage restoration of the system occur only "several times per year" and the number of incidents requiring an operator to be called in to manage restoration of the system in the overnight and weekend periods when the control room is not manned occurred a "few times per year". Energy Probe submitted that the level of activity on the Fort Erie system does not warrant an evening shift for the control room. Manning a control centre for a few incidents annually is not a prudent expense when, by its own admission, CNPI is able to cope with a similar small number of incidents occurring overnight or on weekends simply by calling an operator in to manage system restoration. Energy Probe also noted that CNPI's position that system control operators must work evenings to prepare switching orders and update system maps is without merit because the size of the Fort Erie system and the CNPI line work force is not large enough to generate any substantial changes to the system on a day to day basis nor require extensive switching orders for the following day's work. Energy Probe submitted that $100,000 cost for the evening shift should be denied by the Board unless CNPI can demonstrate that other distributors of similar size and complexity also run evening control room shifts and recover those costs in rates.

In response, CNPI stated that Energy Probe provided a limited description of the functions of the Control Room Operator. The Operator provides oversight for both Port Colborne and Fort Erie and for CNPI Transmission. Control Room costs are allocated to Fort Erie as well as to Port Colborne and Transmission. CNPI is a licenced transmitter and, as such, has obligations under the Transmission System Code and its ancillary operating agreements with Hydro One Networks Inc. and the Independent Electricity System Operator in respect of its operations.

Board Findings

The Board will not make any adjustments to the proposed costs for Fort Erie associated with the Control Room. CNPI has adequately justified the need for the Control Room and the recovery of the costs allocated to Fort Erie.

Regulatory Costs

CNPI's proposed regulatory costs were $475,000, amortized over three years, for the three distribution service areas. For Fort Erie, the proposed regulatory costs are $123,031. For EOP the proposed regulatory costs are $110,771. In both cases, the proposed costs also amortized over three years. The balance is attributable to Port Colborne.

SEC argued that the $475,000 amount for the three services is excessive. SEC submitted that a more appropriate maximum budget would be $300,000.

In response, CNPI noted that when viewed on an individual basis, the proposed amounts for Fort Erie and EOP are reasonable, even when compared to regulatory costs awarded by the Board in other proceedings.

Board Findings

The proposed three-year amortization of the one-time costs associated with the 2009 rates proceeding is acceptable as it is expected that the 2009 rates will be in effect for three years in the case of CNPI. The issue for the Board is whether the one-time costs for Fort Erie and EOP are reasonable for ratemaking purposes.

Comparison with regulatory cost amounts incurred or allowed by the Board for other distributors cannot be a precise exercise for many reasons, including but not limited to, the complexity and quality of the filing, size of the utility, dependence on external resources, type and complexity of proceeding, and intervenor costs. The Board has allowed recovery of amounts both higher and lower than the above amounts for other distributors. The Board concludes that, on balance, it is reasonable in this case to allow $100,000 as one-time regulatory costs to be recovered from ratepayers of Fort Erie and $75,000 as one-time regulatory costs to be recovered from ratepayers of EOP. These one-time costs shall be amortized over three years.

OM&A Cost Benchmarking

SEC proposed that the Board direct CNPI to report in its next rebasing application on tangible OM&A savings it has achieved through its capital spending initiatives and otherwise, and also report on its future plans to get its cost levels in line with comparable Ontario LDCs.

In response, CNPI submitted that it is currently within the purview of the Board to examine CNPI's capital spending in the context of a cost of service application and no special directive is required from the Board. Further, it has not been established the CNPI's cost levels are not in line with comparable Ontario LDC's. Reference to and inferences made with respect to the benchmarking analysis prepared for the Board by Pacific Economics Group ("PEG") are comparative indicators only and have not been tested thoroughly. Any PEG comparative inferences should not be a decisive measure in the Board's Decision.

Board Findings

SEC's suggestion on comparative analysis goes in effect to benchmarking and cohort grouping. The Board will use the results of benchmarking by cohort groupings for the first time for purposes of annual rate adjustments under the 3rd generation incentive ratemaking, beginning in 2010. The Board has not used the results of any benchmarking or cohort groupings for purposes of rate rebasing and it is not evident at this time if it will do so or when. There is no compelling basis in the Board's view to treat CNPI uniquely and distinctly from other distributors and will not make the specific directions sought by SEC. At the next rebasing proceeding, it is open to SEC and others to test the reasonableness of the proposed revenue requirement for CNPI's service areas.

Rate Benchmarking

In its written argument, SEC prepared and included as Appendix "A" a table comparing annual distribution charges (fixed charge and variable charges) for forty electricity distributors and made a number of observations regarding the relative ranking of Fort Erie and EOP, inviting CNPI to propose different comparisons, either by adding more LDCs to the table or by suggesting appropriate cohorts or peer groups.

In reply, CNPI noted that it is troubled by the analysis provided by SEC as it is new evidence that has been introduced after the evidentiary portion of the proceeding ended. CNPI has not had the opportunity to test this evidence through interrogatories or cross examination. CNPI submitted that Appendix "A" should be disregarded by the Board.

Board Findings

The Board agrees with CNPI that this is new evidence that was not presented to CNPI through interrogatories or cross-examination and as such the Board has chosen to not consider it in making its decision. The Board was surprised and disappointed with SEC's approach in this matter.

INCOME TAXES

CNPI is an investor-owned corporation that pays Federal and provincial taxes, in contrast to PILs (Payments In Lieu of taxes) that municipally-owned or provincially-owned distributors are subject to. CNPI is subject to taxes as one corporate entity. It documented the allocation of taxes in a top-down method, allocating between transmission and distribution and then, within distribution, between the three service areas.

Board staff noted the recently-passed Federal Budget has provisions which may impact on a corporation's tax liability for 2009. Board staff submitted that CNPI should flow through applicable changes and update the tax allowance to determine the revenue requirement and rates resulting from the Board's Decision. CNPI agreed.

Board Findings

The Board notes that there is no dispute as to the method and inputs in calculating the final income tax amounts to be reflected in rates. CNPI shall include the appropriate details in the draft rate order.

DEFERRAL AND VARIANCE ACCOUNTS

Disposition of Accounts

In the pre-filed evidence for both Fort Erie and EOP, CNPI sought to dispose of Account 1508 - Other Regulatory Assets over one year. The proposal not to request disposition of other accounts was based on CNPI's understanding that the Board had initiated a review of the disposal of the RCVA and RSVA accounts.

On request by Board staff at the oral hearing, CNPI provided the quantum and impact on rates of other accounts. In its AIC, CNPI stated that it would be amenable to the Board dispersing these accounts as part of this proceeding and that the balances be disposed of over three years.

The balances at December 31, 2007 and interest to April 30, 2009 for Fort Erie and EOP are shown in the tables below (Numbers in brackets are credit to customers).

Account Balances at December 31, 2007 (Fort Erie) (including interest up to April 30, 2009)		
Account Description	**Account #**	**Total ($)**
Other Regulatory Assets - OEB Cost Assessments	1508	43,004
RSVA – Wholesale Market Service Charge	1580	(591,650)
RSVA – One-time Wholesale Market Service	1582	41,864
RSVA – Retail Transmission Network Charge	1584	98,795
RSVA – Retail Transmission Connection Charge	1586	97,446
RSVA – Power	1588	1,108,288
Total		**797,747**

Account Balances at December 31, 2007 (EOP) (including interest up to April 30, 2009)		
Account Description	**Account #**	**Total ($)**
Other Regulatory Assets - OEB Cost Assessments	1508	12,171
RSVA – Wholesale Market Service Charge	1580	(282,563)
RSVA – One-time Wholesale Market Service	1582	-
RSVA – Retail Transmission Network Charge	1584	(159,249)
RSVA – Retail Transmission Connection Charge	1586	(5,990)
RSVA – Power	1588	659,159
Total		**223,528**

Board staff noted that the separate Board initiative for the disposition of commodity account 1588 (RSVA power) and other related RSVAs has not yet been finalized. In this regard however, Board Staff Discussion Paper “Electricity Distributors’ Deferral and Variance Account Review Initiative” (EB-2008-0046) issued on April 1, 2009, proposes that distributors be required to file an application to dispose of all account balances (with a few exceptions such as PILs, CDM, smart meters and account 1590) as part of their cost-of-service application. Board staff submitted that notwithstanding the fact that the Board staff proposal is not yet confirmed Board policy, the Board should order disposition of all of the above stated deferral and variance account balances and not just the disposition of account 1508.

VECC on the other hand submitted that since there is a separate proceeding to examine the disposition of RSVA accounts, it would be premature to approve the disposition of all the named accounts absent further testing.

Board staff noted that the RSVA Power account 1588 comprises Cost of Power and the Global Adjustment sub-account and further that the Cost of Power balance is attributable to all customers, whereas the Global Adjustment balance is attributable to only non-RPP customers. In this regard, Board staff submitted that CNPI should provide for both Fort Erie and EOP:

- the closing balances corresponding to RSVA - Cost of Power account (excluding the global adjustment) and the Global Adjustment sub-account; and
- updated rate riders to reflect the allocation treatment discussed above (i.e., Cost of Power balance is attributable to all customers, whereas the Global Adjustment balance is attributable to only non-RPP customers).

Board Findings

In proceedings for other electricity distributors, the Board has taken various approaches in disposing of the balances in accounts that are the subject of a separate Board initiative. The approach taken in each case is driven by the specific circumstances. In this case, the Board concluded that it would be better to defer the disposition of the other accounts. This is partly due to VECC's submission that the balances in this case have not been adequately tested and partly due to the additional information requested by Board staff which would need to be tested.

The Board accepts the disposition of Account 1508 - Other Regulatory Assets over one year as proposed by CNPI for both Fort Erie and EOP.

International Financial Reporting Standards (IRFS) Deferral Account

CNPI sought the establishment of a deferral account to record costs associated with the transition of utility accounting from Canadian Generally Accepted Accounting Principles to International Financial Reporting Standards.

SEC submitted that such account should not be established except as determined in EB-2008-0408, where the Board is considering IFRS issues in the proper context.

Board Findings

The current Board initiative on this matter is not yet completed and there are no Board pronouncements in this regard. It would be premature for this Board panel to authorize the requested account as it is not exclusive to CNPI. The establishment of an IFRS deferral account is of general sector applicability and there will need to be a sector-wide approach. The Board will not authorize the establishment of the requested deferral account at this time.

COST OF CAPITAL

Capital Structure

The proposed deemed capital structure for both Fort Erie and EOP is 43.3% common equity and 56.7% debt, composed of 52.7% long-term debt and 4.0% short-term debt.

There were no issues raised related to CNPI's capital structure.

Board Findings

The proposed capital structure is compliant with Board guidelines and is approved for ratemaking purposes.

Return on Common Equity

The applications reflected a rate of return on equity of 8.39% based on May 2008 *Consensus Forecast*. On February 24, 2009, the Board issued a letter to all distributors announcing updated cost of capital parameters to be used, in which the maximum rate of return on common equity is 8.01% for 2009.

Board Findings

When CNPI prepares the draft rate orders it shall reflect a maximum rate of return on common equity of 8.01%.

Short Term Debt Rate

The applications reflected a short term debt rate of 3.38% based on May 2008 Consensus Forecast. On February 24, 2009, the Board issued a letter to all distributors announcing updated Cost of Capital parameters to be used, in which the deemed short term debt rate is 1.33% for 2009.

Board Findings

When CNPI prepares the draft rate orders it shall reflect a cost rate for short term debt of 1.33%.

Long Term Debt

CNPI has third-party long term debt of $30 million in senior unsecured notes. These were issued on August 14, 2003, bear interest of 7.092% and are payable at maturity on August 14, 2018.

CNPI also has a $15 million debt obligation to its affiliate FortisOntario. The debt instrument is dated August 13, 2008, bears an interest rate of 6.13% and is callable on demand. The Board's deemed long-term debt rate in 2008 was 6.10%, as announced in the Board's letter of March 7, 2008 on the 2008 Cost of Capital parameters. The $15 million promissory note bears a debt rate of 6.13%, which was set by FortisOntario to match the Board's deemed long-term debt rate at that time.

CNPI forecasts that its debt requirements in the 2009 test year will increase, and expects that the $15 million debt instrument will be recalled and replaced with a $21 million instrument in 2009 Q4. CNPI proposed that the current deemed long-term debt rate of 7.62% should apply to the $21 million debt.

Board staff noted that while the 7.62% updated deemed debt rate is in compliance with the Board's guidelines, it is less than clear about what rate should apply as the CNPI/FortisOntario approach is more complicated than the scenarios contemplated in the Board Report. Board staff submitted that one option could be to treat the affiliated debt as two instruments as follows:

- $15 million at the 6.10% deemed debt rate for 2008, for the promissory note issued in 2008; and
- $6 million new (incremental) debt for 2009 at the updated deemed long-term debt rate of 7.62%.

In SEC's view, the proposal is an attempt to use the Board's policies to recover the maximum amount possible from ratepayers, without consideration of market rates or fairness as between ratepayers and shareholder. SEC submitted that the Board should reduce the revenue requirement by the proposed increase in the amount to be recovered on the existing $15 million indebtedness. The evidence is that CNPI cannot repay that at will, so reduction of the interest rate recoverable to the original 6.13% is an approach that seems fair. As to the additional $6 million, as CNPI has not provided the evidence it should have provided as to market rates, the 6.13% rate should apply at most.

VECC submitted that the Board Report did not seem to contemplate the asymmetrical conditions that exist for CNPI with respect to affiliate long-term debt.

In response, CNPI argued that the debt rate of the $15 million instrument is irrelevant, since it will be recalled and replaced in the 2009 test year. CNPI reiterated that the 7.62% for the full $21 million is consistent with the Board's policies.

Board Findings

Non-arm's length debt arrangements are common in the electricity distribution industry and the Board has adopted guidelines as to how to deal with such arrangements. However, guidelines cannot contemplate every possible debt arrangement that may exist or how it may evolve.

As a general principle, when a debt instrument is callable on demand, this is at the call of the debt holder. The holder will do so if the holder feels that would be beneficial and not do so if it would not be beneficial to the holder. This asymmetry has not been contemplated in the Board's guidelines. The Board therefore will deal with this issue on the specifics of this case.

The evidence is that CNPI will not be in a position to pay the $15 million debt upon demand. It is reasonable to assume that, on the face of no ability to pay, the debt holder who is also the shareholder would not make such demand. It appears that the intent to recall the $15 million existing debt is an attempt to take advantage of the higher refinancing rate of affiliated debt stipulated in the Board's updated cost of capital parameters. If the updated capital parameters were lower than those in 2008, the $15 million loan would not be recalled and CNPI's additional $6 million debt requirements would have been satisfied through alternate arrangements. The additional $6 million debt requirement would be either through third-party debt or through FortisOntario.

In the circumstances, the Board finds it reasonable to deem the cost of the affiliate debt to be the continuation of the $15 million existing affiliated debt with FortisOntario at the rate of 6.13% and an additional $6 million affiliated debt with FortisOntario at the rate of 7.62%.

The Board notes from the evidence that CNPI assumes refinancing in Q4 of 2009 (Undertaking Response JT2.6) but its revenue requirement reflects an amount equivalent to having refinanced in mid year (E6/T1/S1, page 4). The Board directs CNPI to make the necessary adjustments to the cost of debt when it files its draft rate order.

The Board notes that there are no issues raised with respect to the third-party debt of $30 million, and will allow this debt at its documented rate of 7.092%.

When CNPI prepares the draft rate order it shall reflect a cost rate for long term debt that reflects the above debt rates weighted by the principal of each debt instrument.

COST ALLOCATION AND RATE DESIGN

Combination of two classes for EOP

Currently there are two GS>50 customer classes in the EOP service area: a) GS>50 (Regular) and b) GS>50 (TOU). For 2009, EOP proposed to combine these two class into one (GS>50). This proposal is in response to the Board's EB-2007-0594 Decision which directed EOP to eliminate the GS>50 (TOU) class as part of its next rate application. The cost allocation and harmonization proposals reflected this combination of the classes.

No party objected to this proposal.

Board Findings

The Board accepts the proposed combination of the current GS>50 (Regular) and GS>50 (TOU) classes into one GS>50 class for EOP.

Harmonization of Distribution Rates

Currently, CNPI operates three distribution territories, Fort Erie, EOP and Port Colborne, as well as a transmission operation. CNPI operates primarily from a single location, Fort Erie, with a single work force and allocates assets and services to each of these business units. CNPI proposed to harmonize the distribution rates of the Fort Erie and EOP service territories. CNPI's rationale for the harmonization is to eliminate duplicated efforts related to financial and regulatory reporting, regulatory compliance and rate setting. The Port Colbome service territory was intentionally omitted from the harmonization due to restrictions related to the lease agreement with Port Colbome Hydro Inc.

The approach taken by CNPI is to blend the Fort Erie and EOP revenue requirements that had been developed separately and combine them as one. The applicants' evidence and position was that any incremental rate impacts of this design are minimal.

In the harmonized rate design, in general, those costs that have common cost drivers are being harmonized while those with cost drivers unique to the service territory remain segregated. The harmonization would apply to the following:

- Monthly service charges
- Volumetric distribution charges
- Smart Meter Adder

There would not be harmonization for the following charges. These would remain specific to each of the two service territories.

- Low Voltage charges (as these only apply to EOP)
- Distribution loss factors
- Retail transmission rates
- Specific Service Charges

To limit bill impacts, CNPI's harmonization proposal included rebalancing the revenue split between fixed charges and volumetric rates.

Both VECC and Board staff supported the harmonization proposal.

SEC noted that the apparent effect of harmonization appears to be to transfer more than $0.2 million of revenue responsibility from already under-contributing residential customers and over-contributing small GS customers to the already heavily over-contributing large GS customers.

Board Findings

The Board approves the harmonization proposal. CNPI's rationale for the harmonization is appropriate. There are invariably impacts on customers from harmonization, positive and negative. In this case, the Board has noted CNPI's attempts to mitigate the negative impacts with the result that such impacts are not of concern. SEC's concerns are largely an issue of the final revenue-to-cost ratios. The Board deals with revenue-to-cost ratio issues later in this decision.

Low Voltage Charges

Low voltage charges are applicable to EOP only as EOP is an embedded distributor within Hydro One Network's (HONI) distribution system.

The harmonized rates for the EOP service area include an LV rate adder. The proposed adder is based on 2009 forecast LV costs of $95,837. This value was developed prior to the Board's Decision regarding HONI's 2009 Distribution Rates.

VECC invited the applicants to address the impact of HONI's 2009 rates on the forecast LV costs as part of its final argument. In response, the applicant provided calculations to demonstrate that this difference is minimal and does not impact rate design.

VECC also noted that the allocation of the LV costs to customer classes is based on allocation factors derived from the 2006 EDR. VECC submitted that the allocation factors should be updated to reflect the 2009 forecast Retail Transmission Service Rate - Connection revenues by customer class. In response, CNPI agreed that such an exercise may be required given the significant redistribution of costs between the customer classes resulting from the loss of larger customers in EOP.

Board Findings

The Board considers reasonable to direct EOP to adjust the low voltage allocation factors to reflect the 2009 Retail Transmission Service Rate – Connection Charge revenues by customer class, and so directs.

The Board will not direct an update to LV costs based on HONI's 2009 rates as the differences are not material and there is a variance account to capture such differences.

Retail Transmission Service Charges

EOP

EOP is embedded in the distribution system of HONI. In response to Board staff IR #66, EOP stated that an analysis of the relationship between the transmission service charges from HONI and the revenue associated with retail transmission through distribution rates for the years 2006 and 2007 indicates revenue exceeded charges by an average of 15% in both network service and connection service.

HONI has proposed an increase of 11.44% and 5.85% (2009 vs. 2008) in its retail transmission rate for sub-transmission customers for transmission network service and line and transformation connection service respectively.

EOP has proposed a 15% decrease from its 2008 tariff in both its transmission network service rates and line and transformation connection service rates.

These rate movements are tabulated below.

Rate Movements			
	Average percentage spread between revenues and charges 2006-2007	Proposed change in HONI's transmission rates for sub-transmission customers from 2008 to 2009	Proposed change in EOP's retail transmission rates from 2008 to 2009
Network	15%	11.44% increase	15% decrease
Connection	15%	5.85% increase	15% decrease

Board staff submitted that it would be reasonable for EOP to calculate revised network and connection rates which would capture:

- the spread between historical transmission charges and revenue, and
- HONI's proposed 2009 over 2008 increase in its retail transmission rate for sub-transmission customers.

VECC submitted that EOP should revise its retail transmission service charge rates to reflect HONI's proposed 2009 over 2008 increase in its retail transmission rate for sub-transmission customers. VECC also invited CNPI to comment on the impact of historical timing differences between HONI's rate implementation and EOP's rate implementation.

Fort Erie

Fort Erie is directly connected to CNPI's transmission grid. In response to Board staff IR #68, Fort Erie stated that an analysis of the relationship between the transmission service charges and the revenue associated with retail transmission through distribution rates for the years 2006 and 2007 indicates charges exceeded revenues by an average of 3% in network service and 5% in connection service.

The uniform transmission rate is higher by approximately 11.26% and 5.45% (2009 vs. 2008) respectively for transmission network service and line and transformation connection service.

Fort Erie has proposed a 14.26% and 10.45% increase from its 2008 tariff in its transmission network service rates and line and transformation connection service rates respectively.

These rate movements are tabulated below.

Rate Movements			
	Average percentage spread between revenues and charges 2006-2007	Proposed change in uniform transmission rates from 2008 to 2009	Proposed change in Fort Erie's retail transmission rates from 2008 to 2009
Network	-3%	11.26% increase	14.26% increase
Connection	-5%	5.45% increase	10.45% increase

Board Staff submitted that Fort Erie's proposed increase (network and connection rates) which captures both the spread between historical transmission charges and revenue and the 2009 over 2008 uniform transmission rate increase is acceptable.

VECC invited Fort Erie to comment on the impact of historical timing differences between implementation of uniform transmission rates and Fort Erie's rate implementation.

In response, CNPI noted that it has no control over the approval and implementation of HONI's retail transmission service charge rates or the uniform transmission tariff and as a result timing differences are inevitable. CNPI noted that the retail service variance accounts are designed to capture these differences "and are working", and it is likely that any resultant change to rates would be insignificant and any attempt at correcting for this timing difference is temporary.

Board Findings

The Board does not accept EOP's proposal. A more reasonable result would be for the transmission network service rates and line and transformation connection service rates to be reduced from their 2008 tariff levels by 3.56% and 9.15% respectively, and the Board so finds.

The Board accepts Fort Erie's proposal to increase its transmission network service rates and line and transformation connection service rates from its 2008 tariff by 14.26% and 10.45% respectively as reasonable.

Other Charges

Fort Erie and EOP proposed to:

- Continue with all of its currently approved Specific Service Charges in each service area;
- Continue with the previously approved Wholesale Market Service charge of $0.0052 per kWh in each service area;
- Continue to charge $0.0010 per kWh for Rural or Remote Rate Protection in each service area; and

- Continue the current Z-factor rate rider applicable to Fort Erie until August 30, 2009, as was approved by the Board in EB-2007-0514 dealing with storm damage.

No party opposed these proposals.

In a letter to the Board dated December 18, 2008, CNPI had requested approval to charge $0.0013 per kWh for Rural or Remote Rate Protection as per the Board's direction.

Board Findings

Including the change to the Rural or Remote Rate Protection charge to $0.0013 per kWh, the Board finds the proposals acceptable and approves them.

Smart Meter Adder

CNPI currently collects a smart meter rate adder of $0.26 per metered customer per month in EOP and $0.27 per metered customer per month in Fort Erie. Under the harmonization proposal, CNPI proposes to charge a smart meter rate adder of $0.27 per metered customer per month in both service areas.

No party objected to CNPI's proposal.

Board Findings

The Board approves the requested smart meter rate adder of $0.27 per metered customer per month for both Fort Erie and EOP.

Loss Adjustment Factors

Fort Erie

Fort Erie is proposing a Distribution Loss Factor of 1.0357 and a Total Loss Factor of 1.0391 for the 2009 test year, which is the observed average for the three year period from 2005 to 2007.

Both Board staff and VECC submitted that the proposed TLF value is acceptable.

EOP

EOP is proposing a Distribution Loss Factor of 1.0438 and a Total Loss Factor of 1.0719 for the 2009 test year, which is the observed average for the three year period from 2005 to 2007.

Board staff submitted that EOP should provide detailed information about the distribution loss factor when reconfiguration of the distribution system is complete. CNPI noted that it has already begun exploring system reconfiguration opportunities that may lend themselves to technical loss reductions. These include reconfiguration of the East line. CNPI is amenable to discussing these and other opportunities with the Board.

Board staff further submitted that the Total Loss Factor value resulting from the averaging process is acceptable for 2009 rates.

Energy Probe submitted that the line losses to transmit on 39 km of distribution line the generation output from three hydro electric generation stations along the Rideau canal to the Main substation should be borne by the generator and not by CNPI customers. CNPI viewed Energy Probe's suggestion that customers connected to that line be assessed the specific losses on that line to be contrary to the Retail Settlement Code where losses have "postage stamp" consideration.

VECC submitted that it favours an averaging of the 2006 Board Approved distribution loss factor with the 2005 to 2007 actual average. CNPI noted this argument fails to consider the impact of lost industrial loads. The industrial loads were connected at 26 kV and 44 kV distribution voltages; their loss means a greater percentage of total system load is supplied by the 4 kV system and as a result will yield greater losses as a percentage of load supplied. Factoring in historical losses, in the manner suggested by VECC, does not address the reality of the impact of these plant closures. The reality is that the system configuration has changed, likely for the long term, and that change has adversely impacted the distribution loss factor.

Board Findings

The Board accepts the proposed loss factors for Fort Erie as reasonable.

With respect to the EOP, the Board is satisfied with CNPI’s explanations and arguments with respect to the submissions and suggestions made by Energy Probe and VECC. The Board approves CNPI’s proposed loss factors as reasonable.

Revenue-to-Cost Ratios

CNPI’s proposed harmonized revenue to cost ratios (R/C ratios) for each rate class for 2009 are shown in the table below in column 5. The table also shows R/C ratios per the informational filing on a separate and combined basis (columns 1, 2, 3) and the Board policy range (column 6).

VECC submitted that in the Board’s cost allocation model the treatment of the transformer ownership allowance results in an over allocation of costs to those classes where customers generally do not own their own transformers (e.g. Residential and GS<50). In response to a VECC interrogatory, CNPI has provided a revised version of its Cost Allocation Informational filing that corrects this anomaly. However Board staff submitted that there is a mismatch between “Total Revenue” and “Revenue Requirement” apparently because revenue was not adjusted from gross to net of the transformer ownership allowance. As a result Board staff in their submission recalculated the ratios on a combined basis as shown in column 4 of the table. Board staff noted that these ratios should be the starting point rather than the combined informational filing ratios in column 3.

	Revenue to Cost Ratio					
	1	**2**	**3**	**4**	**5**	**6**
	Info. Filing CNPI-EOP	**Info. Filing CNPI-FE**	**Info. Filing Combined**	**Transformer Ownership Allowance Adjusted - Combined**	**Proposed 2009 – Harmonized Rate Design**	**Board Policy Range**
Residential	73.02%	82.69%	80.52%	82.03%	82.88%	85% - 115%
GS < 50 kW	142.48%	129.81%	133.51%	134.23%	120.00%	80% - 120%
GS > 50 kW	158.23%	151.44%	154.80%	148.91%	152.66%	80% - 180%
USL	65.94%	56.76%	57.76%	57.39%	44.69%	80% - 120%
Sentinel Lights	31.77%	37.35%	37.46%	37.78%	54.61%	70% - 120%
Street Lights	27.64%	19.16%	19.51%	20.58%	23.91%	70% - 120%

Board staff further submitted that:

- CNPI should:
  - rebalance rates such that revenue to cost ratios that are outside the Board policy range move to the closest boundary of the range; and
  - assess the rate impact resulting from this action, particularly for residential customers in EOP.
- For those rate classes, where the rate impact
  - is not excessive, the movement of the ratio should be in one step in the first year; and
  - is excessive, the movement of the ratio should be in multiple steps, halfway to the closest boundary of the range in the first year, and in equal steps in the subsequent two years.

In its reply submission, CNPI noted that Board staff's suggested approach is reasonable.

VECC noted that regarding harmonization of cost allocations, CNPI included in EOP the charges from HONI for LV (now ST) service in the base distribution revenue requirement to be allocated. VECC noted that CNPI has agreed that the corrected calculation could be included in its rate derivation.

SEC submitted that the Board order the following:

- R/C ratio of 85% for Residential class
- R/C ratio of 70% for Sentinel Lights and USL classes
- R/C of 37% with a goal of 70% by 2011 for Street Lights
- R/C ratio of 142%with a goal of 137% by 2011 for GS>50 class

SEC further submitted that, with the implementation of the changes proposed, the GS>50KW and GS<50KW classes, containing most of the enterprises that drive the local economy and provide local services, will still be over-contributing at a high level, and the Residential, Sentinel, Street and USL classes will still be under-contributing in substantial amounts, but the level of the cross-subsidy will have been narrowed slightly.

Board Findings

Consistency with Board practice and with earlier 2009 rate decisions made by the Board for other distributors dictates that the move by 50% to the closest boundary of the Board's policy range should be accomplished by starting with VECC's approach, where the transformer ownership allowance is removed and using the R/C ratios in column 4 of the table as a starting point. Therefore, CNPI shall move the:

- Residential class from the new starting point of 82.03% to 83.52%
- USL class from the new starting point of 57.39% to 68.70%
- Sentinel Lights class from the new starting point of 37.78% to 53.89%
- Street Lights class from the new starting point of 20.58% to 45.29%
- GS<50 class from the new starting point of 134.23% to 127.12%

CNPI shall apply the net of the revenue responsibility increase related to the Residential, USL, Sentinel Lights and Street Lights classes and revenue responsibility decrease related to the GS<50 class to reduce the revenue responsibility related to the GS>50 class by moving the R/C ratio from the current starting point of 148.91% to a lower point. This is justified by the fact that the GS>50 class has the highest starting point ratio.

For 2010 and 2011, CNPI shall further move the R/C ratios for the Residential, USL, Sentinel Lights, Street Lights and GS<50 classes to the closest boundary of the Board's policy range in two equal steps. As stated above, CNPI will apply the net of the revenue responsibility increase to move the R/C ratio for the GS>50 class to a lower point.

IMPLEMENTATION AND COST AWARDS

Implementation

Both Fort Erie and EOP requested in their rate applications that their proposed rates be made effective on May 1, 2009. Because the distribution rates for Fort Erie and EOP were made interim as of May 1, 2009, the Board has the jurisdiction to make their rates effective on May 1, 2009.

Both Fort Erie and EOP filed their rate applications on August 15, 2008 in accordance with the Board's January 30, 2008 letter regarding its multi-year rate setting plan. Furthermore, Fort Erie and EOP met all deadlines set out in procedural orders during the course of the proceeding. The delays in the proceeding can be attributed to disputes over the relevance of certain matters raised by intervenors, SEC in particular.

No party opposed the May 1, 2009 effective date.

The Board approves an effective date of May 1, 2009. Given the time that is required for the process leading to the issuance of a rate order and the need for Fort Erie and EOP to implement the new rates into their billing systems, it may not be possible to implement the new rates until September 1, 2009. The foregone revenue from May 1, 2009 to August 31, 2009 shall be recovered through a rate rider in effect from September 1, 2009 to April 30, 2010.

The Board’s findings outlined in this Decision are to be reflected in a Draft Rate Order. The Board expects Fort Erie and EOP to file detailed supporting material, including all relevant calculations showing the impact of the implementation of this decision in its proposed revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates, including bill impacts. Supporting documentation shall include, but not be limited to, filing a completed version of the Revenue Requirement Work Form excel spreadsheet, which can be found on the Board’s website. Fort Erie and EOP should also show detailed calculations of any revisions to their rates and charges.

A final Rate Order will be issued after the following steps have been completed.

1. Fort Erie and EOP shall file with the Board, and shall also forward to intervenors, a Draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision, within 21 days of the date of this Decision.

2. Intervenors shall file any comments on the Draft Rate Order with the Board and forward to Fort Erie and EOP within 7 days of the date of filing of the Draft Rate Order.

3. Fort Erie and EOP shall file with the Board and forward to intervenors responses to any comments on its Draft Rate Order within 7 days of the date of receipt of intervenor submissions.

Costs Awards

The Board has concluded that it would be easier for all parties concerned if intervenors filed their cost claims at one time for all three of CNPI's cases. Therefore, the Board will issue its directions regarding cost awards for all three cases at the time it issues its decision in the Port Colborne case (EB-2008-0224).

DATED at Toronto, July 15, 2009

ONTARIO ENERGY BOARD

Original signed by

____

Paul Vlahos
Presiding Member

Original signed by

____

Ken Quesnelle
Member

IN THE MATTER OF

TERASEN GAS (VANCOUVER ISLAND) INC.
AND
TERASEN GAS INC.

SYSTEM EXTENSION AND CUSTOMER CONNECTION POLICIES REVIEW

DECISION

December 6, 2007

Before:

Anthony J. Pullman, Commissioner

So far as concerns the ongoing administration of the Companies main extension and service line policies the Commission Panel directs Terasen to update all Geo-codes and MX test input parameters at the beginning of each year. To determine the appropriate Geo-code for each area, both historical costs and a forecast of future costs will be used. Terasen is to provide the Commission with schedules comparing the existing and updated Geo-codes and MX test input parameters. Given that the 2002 REUS does not include TGVI data, the REUS use per appliance should not be used to estimate TGVI consumption, and the Commission Panel directs Terasen i) to update the consumption estimates in the TGVI MX test to reflect TGVI use per appliance; and ii) to reflect in the Companies' MX tests their experience of consumption "ramp-up" in the early months of service.

The Commission Panel directs the Companies to file with the Commission on an annual basis, within 90 days of calendar year end, a Main Extension Report including the following:

- a review of a random sampling of MX test results representing a confidence interval of +/-12 percent at a 95 percent confidence level and the five highest cost main extensions to determine if the aggregate PI thresholds need to be adjusted on a go forward basis in order to achieve the aggregate PI of 1.1. The review is to include a comparison of forecast and actual costs; consumption; and PI for the first five years of main extensions in the sample;
- a concise explanation of the random sampling methodology used ; and
- a comparison of the forecast and actual cost for all service line and main extension installations.

4.4 SLCA and SLIF for New Mains Extensions

Terasen proposes to change the process for determining service line costs as part of a main extension test. When a new main extension is required, Terasen proposes that all the capital costs required to provide service to the customer (main extension, service line and meter) will be input into the MX test and a distinction between service line and main will not be made, therefore eliminating the requirement for the SLCA. Terasen also proposes to eliminate the SLIF for all customers requiring a main extension (Exhibit B-1, p. 26).

Principles of Public Utility Rates

Second Edition

by
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the competing objectives of ratemaking that are difficult to resolve, thus making the climb to the peak of Mount Pareto slippery. While our preference as economists is to make greater use of the criterion of service at cost as the standard by which alternative rate structures are compared, we realize that to expect this bias of others would be hopelessly naîve. We do believe, however, that the ratemaker should utilize the cost standard as a benchmark, with assessments of the efficiency advantages (or disadvantages) of particular rate structures playing a subsidiary role; social and fairness standards also may be appropriate within the limits of authority that a regulating body may be able to exercise. As the French thinker Blaise Pascal noted: "We know the truth not only by reason, but also by the heart."

CRITERIA OF A DESIRABLE RATE STRUCTURE

Throughout this study we have stressed the point that, while the ultimate purpose of rate theory is that of suggesting criteria of reasonable rates and rate relationships, an intelligent choice of these depends primarily on the accepted *objectives* of ratemaking policy and secondarily on the need to minimize undesirable side effects of rates otherwise best designed to attain these objectives. However, no rational discussion of the relative merits of cost of service and value of service, for example, as standards of desirable rates or rate relationships is possible without reference to the question of what desirable results the ratemaker hopes to secure, and what undesirable results are to be minimized, by a choice between or mixture of the two standards. This was recognized explicitly in the Electric Utility Rate Design Study sponsored by the National Association of Regulatory Utility Commissioners (NARUC) and undertaken by the Electric Power Research Institute (EPRI) (See Malko, Smith and Uhler, 1981, p. 1-6). Not only this: the very *meaning* to be attached to ambiguous, proposed standards such as those of "cost" and "value" — an ambiguity not completely removed by the addition of familiar adjuncts, such as out-of-pocket costs, or marginal costs, or average costs — must be determined in the light of the purposes to be served by the public utility rates as instruments of economic policy. This is a commonplace; but it is a commonplace which, so far from being taken for granted, needs repeated emphasis.

In this section we first outline a set of attributes to be sought in the development of a sound rate structure. While we know that regulation will not guarantee good economic performance, we should at least like it to arrest or curb egregiously bad performance. For instance, regulation should allow a fair rate of return, but not guarantee or protect a regulatee against mismanagement or adverse business conditions. Sound rate relationships are essential to the attainment of these desirable ends, but criteria are required to judge whether, and to what extent, these objectives have been attained. In our attempt to put the competing criteria into an explicit form we recognize that we are violating the sage advice of Charlie Brown that: "No problem is so big that it can't be run away from."

Attributes of a Sound Rate Structure

What are the attributes to be sought in the development of a sound rate structure? Many different answers have been suggested in the technical economics literature and in the reported opinions by courts and commissions. A number of writers have summarized their answers in the form of a list of desirable attributes of a rate structure, comparable to the canons of taxation found in Adam Smith's *Wealth of Nations* (1937 — originally 1776) and subsequent treatises on public finance. In very general terms (see e.g., Federal Energy Regulatory Commission, Order No. 436, October 9, 1985) optimal rates: should provide clear, efficient, effective, informative, and cost-effective market signals about the present and the future cost of service to buyers and sellers, (which requires that prices track costs); should embody strong incentives for optimal present and future cost and service quality configuations; should give buyers and sellers optimal flexibility in selecting sellers and buyers respectively; should allow utilities to serve as agents of progress; should maintain or improve distributive equity, and should allow for the attainment and maintenance of a flexible (non *ad hoc*) regulatory framework with a modicum of necessary delay and obfuscation (and even a willingness of a commission to dissolve itself under the appropriate competitive or contestable conditions!). But this is a pretty general menu, and more specific direction is needed when applying them to an empirical world. As someone once said, "the real world is only a special case of the theoretical world, and not a very interesting one at that." But many practical-minded people would disagree, so let us push on to greater specificity.

The list that follows is fairly typical, although we have derived it from a variety of sources, instead of relying on any one presentation. Of the ten proposed attributes enumerated in this section, the first three relate to the provision of adequate stable and predictable revenues and rates; the next five are based on cost, efficiency, and equity considerations, and the remaining two deal with matters of practicality and acceptability. However, the sequence in which the ten attributes are presented is not meant to suggest any order of importance. Moreover, there is, perforce, some inconsistency and redundancy in any such listing. We are simply trying to identify the desirable characteristics of utility performance that regulators should seek to compel through edict.

Revenue-related Attributes:

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.

2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.

3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity. (Compare "The best tax is an old tax.")

Cost-related Attributes:

4. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

5. Reflection of all of the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities).

6. Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three

dimensions: (1) *horizontal* (i.e., equals treated equally); (2) *vertical* (i.e., unequals treated unequally); and (3) *anonymous* (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).

7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).

8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

Practical-related Attributes:

9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.

10. Freedom from controversies as to proper interpretation.

Lists of this nature are useful in reminding the ratemaker of considerations that might otherwise be neglected, and also useful in suggesting important reasons why problems of practical rate design do not yield readily to scientific principles of optimum pricing. But they are unqualified to serve as a base on which to build these principles because of their ambiguities (how, for example, does one define "undue discrimination"?), their overlapping character, their inconsistencies, and their failure to offer any basis for establishing priorities in the event of a conflict. For such a basis, we must start with a simpler and more fundamental classification of ratemaking functions and objectives.

Some of these attributes in the aforementioned list are based directly on the primary functions of public utility rates first presented in Chapter 4, and the related objectives to be sought in the establishment of a cost-based standard of ratemaking (Chapter 5). These objectives provided the basis for development of the criteria of a fair return (Chapter 10). These same objectives, derived from the four primary functions, can now be used to specify the criteria of a sound rate structure discussed in the following section.

The Primary Criteria Are Based on the Objectives of Regulation

General principles of public utility rates and rate differentials are necessarily based on simplified assumptions both as to the objectives of ratemaking policy and as to the factual circumstances under which these objectives are sought to be attained. Attempts to make these stated principles subserve all special objectives and cover all specific conditions would be hopeless. Writers on the theory of rates are therefore at liberty to base their analyses on the acceptance of those objectives which are of wide application and the attainment of which may be aided by whatever tests or measures of sound rate structure the analyses suggest.

Among these objectives, the following three may be called primary, not only because of their widespread acceptance, but also because most of the more detailed objectives discussed in the literature are ancillary thereto: (1) the revenue-requirement, production-motivation, or financial-need objective; (2) the optimum-use, demand control, or consumer-rationing objective; and (3) the compensatory income transfer function or fair-cost-apportionment objective. Based on these objectives we propose the following three primary criteria by which to judge the soundness and desirability of a rate structure for public utility enterprises. As outlined below, these objectives are related closely to five of the ten attributes specified above.

Criterion 1 - Capital Attraction

(Attribute 1): based on the revenue-requirement objective, with due regard to potential problems of socially undesirable levels of rate base, product quality, and safety; it takes the form of a fair-return standard with respect to private utility companies;

Criterion 2 - Consumer Rationing

(Attributes 4 and 5): based on the consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between the private and social costs incurred and benefits received;

Criterion 3 - Fairness to Ratepayers

(Attributes 6 and 7): fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed *fairly* and without arbitrariness, capriciousness, and inequities among the beneficiaries of the service and so as, if possible, to avoid undue discrimination.

The objectives specified above correspond to three of the four primary functions of utility rates set forth in Chapter 4. The efficiency-incentive function, or that of encouraging managerial efficiency, is omitted because of its more direct bearing on the desirable criteria for a fair rate of return. Some writers, especially the older ones, e.g., Wallace (1941, pp. 475-478) would add a fifth objective: that of benefitting specific classes of ratepayers, such as customers of substandard income or a depressed industry. This objective comes under the heading of social principles of ratemaking as we have used the term in Chapter 8.

In actual rate cases, these three objectives of reasonable rates and rate relationships, and particularly the last two, are by no means always sharply distinguished. But the distinction may be illustrated by the imagined example of a request, submitted to a regulating commission by a group of ratepayers, that an electric (gas or telecommunications) company be ordered forthwith to abandon its present, somewhat elaborate, schedule of class rates, block rates, and two-part or three-part tariffs in favor of a uniform kilowatt-hour (therm or message minute) rate for all customers throughout its franchise territory. Almost certainly this proposal would be held subject to the threefold objection:

(a) that no uniform rate, however high, could be made to yield a fair return on the company's invested capital;

(b) that, even if it could do so, rate uniformity despite lack of cost uniformity in the supply of different types of service would impose *unfair* and discriminatory burdens on the consumers of the less costly services; and

(c) that, quite aside form its unfairness, the uniform rate would result in a serious underutilization of plant capacity because it would cut down the demand for services (especially, for off-peak services) that could be supplied at incremental costs materially below average unit costs, while stimulating a wasteful on-peak demand for services that can be supplied only at incremental costs higher than average costs and it does not reflect any differential social costs and benefits in different areas.

Some writers who confine their attention to what they call the "economic" principles of public utility rates have ignored the third criterion of a sound rate structure in their development of their principles of public utility rates on the ground that fairness questions are beyond the competence of professional economists (on the general issue of fairness, see Zajac, 1985, and Baumol, 1986). Instead, they have centered attention on the second criterion, often with special reference to its application under the constraint of a revenue-requirement constraint. But a refusal to recognize fairness issues as relevant to the design of a sound rate structure would so far remove the analysis from the objectives of Chapter 5 and divorce theory from practice that these issues will not be completely ignored in the discussion that follows.

Stability and Predictability of Rates: A Secondary Criterion

Attributes 2 and 3 on stability and predictability have been neglected relative to those associated with the three primary criteria, and deserves further consideration. In ratemaking, the attribute of *predictability*, is more important than *stability* per se. Time-of-use rates, for example, are not stable (in a strict sense), but are predictable and, most would agree, desirable. One could certainly argue that ratepayers should be given the information they need to *predict* rates accurately. However, this does not imply a necessary need to keep rates stable at the expense of otherwise efficient pricing. For instance, in the case of rate base valuation, most jurisdictions opted for the rate stability associated with original costs (also for the popular understanding and administrative practicality) even though this method has an economic cost in terms of ideal resource allocation and use during periods of changing price levels. In that case, the presumably intelligent choice between the merits and demerits of the alternatives led decisionmakers to conclude that the price society pays for this stability is reasonable.

Stability, like freedom, is not free. Utility regulation can and does affect the social cost of risk bearing (Schmalensee, 1979, p. 36-37). The bearers of risks have real costs imposed on them. Economic efficiency calls for the one's best able to bear risk to do so. Ideally, the regulatory process only redistributes and does not increase total risks. Erratic regulation can increase a firm's real costs, including capital costs. Stabilized rates (returns) shift risks from ratepayers (shareholders) to shareholders (ratepayers). Utilities need revenue stability to mitigate the sunk costs of their highly specialized systems that make them prime candidates for expropriation or opportunism. However, as Yandle (1987) puts it: "You can fleece a sheep many times, but you can only skin him once."

A monolithic critic might ask: why place such great importance on revenue and rate stability and predictability when no such constraints operate in the unregulated sector (especially in light of the business cycle)? The answer to this question is provided in great detail in the next two chapters. For the moment, let it suffice to note five major considerations. First, some users have a strong preference for rate stability in planning even if it means some sacrifice in the (higher) level of initial rates. This is especially true of customers who use the utility in the production of other goods and services and who fear that rivals may obtain advantages by acquiring the service more cheaply and reliably elsewhere (Baldwin, 1987, p. 225). Second, there are transaction costs involved in the determination, administration, and publicity of a rate structure; these include advertising, publishing and distributing price lists, issuing new catalogs, etc. Third, since the greater asset-specificity in regulated markets provides more scope for opportunistic behavior, assurances of predictable revenues are appropriate in a regulated industry. Fourth, rate stability and more particularly predictability, are needed to allow the users to secure a rational control of demand. We want to make sure that regulation does not increase, but only redistributes the total and real risk. Therefore, a fourth criterion, although of a somewhat lower rank than the three primary ones discussed earlier, is that of stability and predictability of specific rates and of revenues.

Some Simplifying Assumptions

In the remainder of this Part Four, except for the sections in Chapter 17, the principles governing the development of a sound rate structure will be discussed under the assumption that rates are designed primarily to subserve the four primary objectives of ratemaking policy specified earlier. But in order to avoid extreme complexities, the following four explicit assumptions are made, all of which are implicit in much of the literature on public utility rates. Some of these are reiterations of the criteria, whereas others are additional assumptions required for clarity.

In the first place, we shall impute an unqualified priority to the fair-return standard of reasonable rate levels despite the fact, noted in Chapter 10, that no such priority is accorded either by legal doctrine or by ratemaking practice. That is to say, we shall assume that the rates of any given utility enterprise, taken as a whole, must be designed as far as possible to cover costs as a whole including (or plus) a fair return on capital investment.

In the second place, we shall assume the availability of a wide range of alternative rate structures, any one of which could be made to yield the allowed fair return on whatever capital investment is required in order to supply the services demanded. This assumption, which implies that the utility enterprise in question enjoys a substantial degree of monopoly power, permits us to center attention on a choice among rate structures, any one of which would be equally fair to investors and equally effective in maintaining corporate credit.

In the third place, throughout this handbook, we operate under a general presumption that pricing at marginal cost would lead to a revenue shortfall; i.e., the firm operates in the range of declining unit costs. However, there is evidence now to suggest that there are certain aspects of utility operations, such as the generation of electricity, which are in the range of increasing unit costs. Thus, the possibility exists that a company could find itself overall in the increasing cost range. This nontrivial possibility should be kept in mind in discussions of the problem of revenue reconciliation.

And in the fourth place, except for incidental references, we shall rule out all of those social principles of ratemaking, discussed in Chapter 8, which may justify the sale of some utility services at less than even marginal costs. While the rate structure may be used as a tool for redistributing income, economists in general prefer alternative fiscal policies, such as taxation and direct subsidies. This is so primarily because of the limited span over which any single regulatory body may exercise control. Thus, the positive realities impinge on our normative analyses.

IMPORTANCE AND LIMITATIONS OF THE PRINCIPLE OF COST OF SERVICE

Cost-of-service as a Basic Standard

Without doubt the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service. For example, based on their extensive researce associated with the Electric Power Research Institute (EPRI) rate design study, Malko, Smith and Uhler (1981, Chapter 4) conclude that "In general, cost-based rates satisfy the commonly held multidimensional, sometimes conflicting, pricing objectives better than noncost-based rates". In the literature, the cost-of-service measure is generally given a dominant position even by writers who insist upon, or reluctantly concede, the necessity for deviations from cost in the direction of value-of-service principles or of various social objectives of ratemaking. However, Stanley (1984) argues that because of the interdependency among ratepayers of basic service and the deterrence effects of the connection charges — e.g., access to the telephone network — the optimal price would be set *below* marginal cost with subsidization by nonbasic services such as the Yellow Pages, Touch-Tone service, long-distance service, etc. Be that as it may, in actual practice there is usually an obvious, marked degree of correlation between the relative charges for different amounts and types of service and the relative costs of rendition.

Of course, there are important exceptions. Local telephone rates, with their customary flat charges, or club pricing, regardless of time of day, or even more important, regardless of duration, come close to providing an outright exception. Thus, by and large, rates are much higher during peak periods; charges also vary directly with duration and distance. Electric utility rates deviate from a cost standard much less than telephone rates. But it is a testimony to the prestige of this standard that, whenever actual or proposed electric tariffs are criticized for their asserted unfairness, the criticism usually takes the form of the contention that the rate relationships fail to conform to cost relationships. When this complaint is made before a public service commission, the defenders of the rates are likely to feel in a much stronger position if they can meet it on its own ground, without having to rely on value-of-service arguments in support of preferential rates to favored classes of ratepayers, unless they can associate them with socially optimal, but often practically intractable, Ramsey pricing (See Chapter 20).

The basic reasons in support of a cost-of-service standard of public utility rates and rate relationships have already been discussed at length in the early chapters of this book, particularly in Chapter 5. Here we may recall that the defense rests both on considerations of optimum utilization or consumer rationing (Criterion 2), and on considerations of fairness as among the different ratepayers (Criterion 3). As to the issue of optimum utilization, this same cost standard (or, at least, a standard of the same name) comports with the consumer sovereignty principle, under which ratepayers should be encouraged to take whatever types of service, in whatever amounts, they wish to take as long as they are made to indemnify the utility enterprise for the costs of rendition. As to the issue of fairness, a cost-price standard, especially one that reflects both private and social costs (and benefits) to the cost causer, probably enjoys more wide-spread acceptance than any other standard except for the even more popular tendency to identify whatever is fair with whatever is in one's self-interest.

Reasons to Deviate From A Cost-of-service Standard

In view of what has just been said, one might suppose that the theory of public utility rate structures or rate differentials would call for acceptance of the same principle already accepted in the determination of entire rate levels, namely, the principle of service at cost. Just as, under the fair-return standard, rates as a whole should cover costs as a whole, so the rates for any given class of service (e.g., residential versus commercial) should cover the costs of supplying that class. And so the rates charged to any single customer within that class should cover the costs of supplying this one customer. Under this assumption, the theory of rate structures would be reduced to a mere theory of cost determination through the aid of modern techniques of cost accounting and cost analysis.

Unfortunately, no such simple identification of reasonable rates with rates measured by costs of service is attainable. One major reason is due to the excessive complexity of the cost relations, or, in the spirit of transaction cost economics, one might say it is due to considerations of bounded rationality, or the cognitive limitations upon the human mind to perceive and process all relevant information. Two other reasons are due to the inherent conflict between a cost-based system of reasonable rate levels and a cost-based system of specific rates and rate relationships. The sources of this conflict lie, on the one hand, in the fact that incremental costs are nonadditive so cost-based rates under circumstances of decreasing cost will fail to meet a company's revenue requirement. On the other hand, the problem of joint and common costs makes it impossible to allocate, at least on a cost basis, the costs attributable to specific classes and units of service. We turn now to a discussion of these sources of possible conflict.

Excessive Complexity of Cost Relationships. The practical reasons for deviating from a cost of service standard lie in the extreme difficulties of cost-of-service measurement together with the fact that, even if all specific costs could be measured, they would be found too complex for incorporation in rate schedules. Most public utility companies supply many different kinds of service even when they confine their activities to nothing but electricity, or gas, or water, or telephone service, etc. In a very real sense, moreover, the supply of any one type of service to thousands of ratepayers at different locations constitutes the supply of a different product to each customer. Similarly, service rendered at any one time is not the same product as an otherwise comparable service rendered at another time.

But these millions of different service deliveries by a single public utility company are produced in combination and at total costs, most of which are joint or common either to the entire business or else to some major branch of the business. Under these circumstances, the attempt to estimate what part of the total cost of operating a utility business constitutes the cost of serving each individual ratepayer or class of ratepayers would involve a hopelessly elaborate and expensive type of cost analysis. For this reason alone, the most that can be hoped for is the development of techniques of cost allocation that reflect only the major, more stable, and more predictable cost relationships.

But even if, through the miracles of high speed megacomputers and of techniques of econometrics, all significant cost differentials could be measured without inordinate expense, they would then be found far too numerous, too complex, and too volatile to be embodied in rate differentials. Stability and especially predictability of the charges for public utility services are desirable attributes; and up to a certain point — or rather, up to an indeterminate point — they are worth attaining even at the sacrifice of nice attempts to bring rates into accord with current production costs. Indeed, to be effective as a means of securing a rational control of demand, ratemaking policies must be sufficiently stable, and even more so, predictable, to permit ratepayers to determine with some confidence what the charges for service will be *if they decide* to equip their home or factory to take the service. Practical considerations such as these have led to the design of rate structures that ignore many cost differentials, as illustrated by the general uniformity of rates for gas, electricity, telephone service, and water supply throughout an entire city, despite distances from source of supply, differences in density of population, and other differences that may have a material bearing on relative costs of service. Indeed, in some parts of the country, the rates of large electric power systems are uniform throughout the state, no distinction being made between urban and rural areas. Critics of this "blanket rate" policy may well be right in insisting that it carries the principle of uniformity too far. But the criticism is not leveled against a disregard of cost differentials in ratemaking, but merely against an *excessive* disregard of them.

Failure of the Sum of Costs to Equate with Total Costs. A further limitation of the cost-of-service principle of rate structures under conditions of natural monopoly lies in the nonadditive character of costs when defined as marginal or incremental costs (See Chapter 17). Such costs cannot be allocated to specific classes or quantities of utility service strictly on a cost responsibility basis because the sum of the parts falls short of equalling the whole. Thus, the requirement that rates as a whole shall equal costs as a whole cannot be reconciled with a requirement that each ratepayer shall pay only the costs for which he or she, and no one else, is causally responsible; nor can it be reconciled with a requirement that each major class of ratepayers shall pay rates designed to cover the costs of serving that class, no more and no less. In consequence, under circumstances of decreasing costs, one of the two cost principles — the total-cost principle or the specific-cost principle — must give way. And, under the assumptions of this chapter, the principle that must yield is that of service at cost as a measure of particular rates and rate relationships.

In stressing this probable conflict between the over-all-cost standard of entire rate levels and the specific-cost standard of the rate structure, the literature on rate theory has attributed it primarily to the distinction between average accounting (or embedded) cost and incremental or marginal cost — a distinction familiar to the microeconomic textbooks on the theory of price determination. Economists naturally have a preference for marginal over average costs, but as Malko and Nicolai (1985) have shown, each has its advantages and disadvantages. This distinction is now duly noted, although a second distinction will receive attention later. The point is that, when multiple products, or even multiple units of the same product, are produced jointly or in common, by an organically whole productive process, the only costs allocable solely to any given product or amount of product are *differential* costs. They are measured by a comparison between the total costs of the entire operation with the given output included, and the total costs with that output excluded. Under limited conditions, however, it is permissible to regard the net cost of one product, among a complex of jointly produced products, as measured by the total cost of producing the whole complex minus the proceeds of the sale of all the other products. These other products are then treated as byproducts in the strictest sense of this term.

The most familiar and most significant form of a differential cost is incremental cost — the increment in total cost that will result from superimposing the production of the particular amount and type of product under inquiry on the other production. A special type of incremental cost, important for the theory of public utility rates, is marginal cost — a concept subject to various definitions but here best defined in a loose way, as the incremental cost, per unit, of producing a relatively small increment of a given product. Marginal cost is sometimes defined as the change in total cost resulting from the production of one unit change of the product. But a one-unit margin is too narrow for most ratemaking purposes. However, these differential or incremental or marginal costs are nonadditive except under a very special set of conditions.

The nonadditive nature of incremental costs applies to all public utility companies which produce services of different kinds for many different people and in many different amounts. With an electric utility company, for example, the only cost specifically allocable to the residential service, *and not* to any other service, is the excess in total cost over what would be the cost of supplying all services other than residential. And the same statement would apply to an attempt to measure the cost that a company has actually incurred, or would incur in the future, in supplying a particular amount of service to any single customer. The natural monopoly assumption ensures that the addition of incremental costs of all services will result in the sum of these costs falling short of total costs. When this assumption is valid, it implies that a public utility company cannot cover its total revenue requirements without charging *more* than incremental costs for at least some of its services.

The nonadditive character of the costs specifically allocable, on a cost-responsibility basis, to the different classes and amounts of public utility services has often been disguised by the acceptance of elaborate full-cost apportionments which begin with total costs and apportion these costs among the various classes of service as one might divide a pie among the members of a dinner party, leaving no residue for the kitchen. Historically, but not presently, these fully-distributed apportionments were done in the railroad field under formulae developed by the ICC. The usefulness of any such apportionments is a debatable subject, which will be discussed in Chapter 19. But, in any case, their merits must rest on a claim that they represent, not a finding of the costs definitely occasioned by one class of service rather than another, but rather a *fair* or *equitable* division of total costs or else a statement of relative, not absolute costs. Even the cost analysts who make these full-cost apportionments recognize this fact implicitly when they concede, as they usually do, that a company may find it profitable to sell some classes of service at less than their imputed costs.

Inconsistent Application of Incremental Cost Principles. Public utility companies have sometimes invoked a marginal or incremental cost principle in defense of special rate concessions to very large customers, or to residential customer, or to municipalities (e.g. street lighting) the defense resting on the contention that the revenues from the favored service will cover, or more than cover, all *additional* costs of its production. The weakness of this defense lies not, as sometimes asserted, in the invalidity of the incremental cost principle, but rather in a company's unsymmetrical proposal to base the preferential rate on incremental cost while basing the other rates on residual cost. Even this latter proposal may be justified in special cases; but the practice constitutes a form of rate discrimination, not a form of cost-based pricing. Its reasoning, according to Taggart (1959, pp. 538-539) has been rejected as a defense against the charge of unlawful discrimination under the provisions of the Robinson-Patman Act. And as Rowe (1959, p. 594) cogently observed: "The differential cost approach to cost justification is totally unacceptable. This means that a cost cannot be ignored *merely* because a given cost category would not be changed by the acquisition or loss of a certain customer or order or quantum of production."

The Fixed Versus Avoidable Cost Dilemma. In short, then, there are two quite different sources of possible conflict between a cost-price system of reasonable rate levels and a cost-price system of specific rates and rate relationships — i.e., (1) joint costs and (2) nonadditive costs. But, if the revenue requirements of the company are lower than would be the requirements of a new company, as they are likely to be during a period of rising construction costs and rising site values, the two sources of conflict may result in a partial offset. It is with this possibility in mind that some economists, who view with regret the necessity of charging public utility rates in excess of marginal costs, have tended to favor an original-cost type of rate base during a period of price inflation. The source of this problem is inherent in the nature of rate of return regulation as practiced in the United States, simply because the "cost" used as a measure of total revenue requirements is not the same kind of cost as the "cost" most clearly relevant to the design of the rate structure. The former depend at least in part on historical or unavoidable fixed costs, whereas the latter depend exclusively on anticipated or avoidable costs. More specifically, a company's total revenue requirements, as measured under a fair-return standard, depend on liabilities and quasi liabilities for the payment of operating expenses and capital costs already partly predetermined by earlier transactions, including earlier purchases of plant, land, and other resources. On the other hand, the costs most clearly relevant to the determination of specific rates, at least under an optimum-utilization objective of ratemaking policy, are those anticipated costs that can still be avoided or minimized by a control of output.

This important distinction between the two types of cost is drawn most sharply when the revenue requirements are determined under an original-cost rule of ratemaking. But the distinction remains, though in a blurred status, even under a fair-value rule as actually applied by courts and commissions. One source of the problem is the impossibility of allocating the historical costs of standard accounting when the objective is to determine the specific costs of producing any given product among a complex of products (Machlup, 1952, Chapter 1).